# 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, 2017**

**OR**

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

**For the transition period from to .**

**Commission file number: 001-33610**

# REX ENERGY CORPORATION

**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware**<br>**(State or other jurisdiction of incorporation or organization)** | **20-8814402**<br>**(I.R.S. employer identification number)** |

**366 Walker Drive**
**State College, Pennsylvania 16801**
**(Address of principal executive offices) (Zip Code)**

**(814) 278-7267**
**(Registrant's telephone number, including area code)**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files) Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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-2of the Exchange Act.

| | | | |
|---|---|---|---|
| Large accelerated filer | ☐ | Accelerated filer | ☐ |
| Non-accelerated filer | ☐ (Do not check if a smaller reporting company) | 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 ☒

9,935,383 shares of common stock were outstanding on November 10, 2017.

**REX ENERGY CORPORATION**
**FORM 10-Q**
**FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2017**
**INDEX**


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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Some of the information, including all of the estimates and assumptions, in this report contains forward-looking statements within the meaning of sections 27A of the Securities Act of 1933, as amended, and 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this report, including, but not limited to, statements regarding our future financial position, business strategy, budgets, projected costs, savings and plans and objectives of management for future operations, are forward-looking statements. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "estimate," "anticipate," "believe" or "continue" or the negative thereof or variations thereon or similar terminology.

These forward-looking statements are subject to numerous assumptions, risks, and uncertainties. Factors that may cause our actual results, performance, or achievements to be materially different from those anticipated in forward-looking statements include, among others, the following:

- economic conditions in the United States and globally;
- domestic and global supply and demand for oil, natural gas liquids ("NGLs"), and natural gas;
- realized prices for oil, natural gas and NGLs and volatility of those prices;
- the adequacy and availability of capital resources, credit and liquidity, including, but not limited to, access to additional borrowing capacity and our inability to generate sufficient cash flow from operations to fund our capital expenditures and meeting working capital needs;
- our ability to comply with restrictions imposed by our term loan credit agreement, secured and unsecured indentures, and other existing and future financing arrangements;
- our ability to service our outstanding indebtedness;
- impairments of our natural gas, NGL and condensate asset values due to declines in commodity prices;
- conditions in the domestic and global capital and credit markets and their effect on us;
- new or changing government regulations, including those relating to environmental matters, permitting or other aspects of our operations;
- the willingness and ability of the Organization of Petroleum Exporting Countries to set and maintain oil price and production controls;
- the geologic quality of our properties with regard to, among other things, the existence of hydrocarbons in economic quantities;
- uncertainties inherent in the estimates of our natural gas, NGL and condensate reserves;
- our ability to increase natural gas, NGL and condensate production and income through exploration and development;
- drilling and operating risks;
- counterparty credit risks;
- the success of our drilling techniques in both conventional and unconventional reservoirs;
- the success of the secondary and tertiary recovery methods we utilize or plan to employ in the future;
- the number of potential well locations to be drilled, the cost to drill, and the time frame within which they will be drilled;
- the ability of contractors to timely and adequately perform their drilling, construction, well stimulation, completion and production services;
- the availability of equipment, such as drilling rigs, and infrastructure, such as transportation, pipelines, processing and midstream services;
- the effects of adverse weather or other natural disasters on our operations;
- competition in the oil and gas industry in general, and specifically in our areas of operations;
- changes in our drilling plans and related budgets;
- the success of prospect development and property acquisitions;
- the success of our business and financial strategies, and hedging strategies;

- uncertainties related to the legal and regulatory environment for our industry and our own legal proceedings and their outcome;
- our ability to maintain the listing of our securities on the Nasdaq Capital Market or any other exchange on which our securities trade; and
- other factors discussed under "Risk Factors" in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2016 filed with the Securities and Exchange Commission.

Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by such statements. You are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date of this report. Other unknown or unpredictable factors may cause actual results to differ materially from those projected by the forward-looking statements. Most of these factors are difficult to anticipate and may be beyond our control. Unless otherwise required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

All forward-looking statements attributable to us are expressly qualified in their entirety by these cautionary statements.

**Item 1. Financial Statements.**

**REX ENERGY CORPORATION**
**CONSOLIDATED BALANCE SHEETS**
**($ in Thousands, Except Share and per Share Data)**

| | September 30, 2017 (unaudited) | December 31, 2016 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and Cash Equivalents | $ 3,234 | $ 3,697 |
| Accounts Receivable | 25,167 | 25,448 |
| Taxes Receivable | 48 | 211 |
| Short-Term Derivative Instruments | 3,904 | 1,873 |
| Inventory, Prepaid Expenses and Other | 3,524 | 2,546 |
| **Total Current Assets** | 35,877 | 33,775 |
| **Property and Equipment (Successful Efforts Method)** | | |
| Evaluated Oil and Gas Properties | 1,022,857 | 1,053,461 |
| Unevaluated Oil and Gas Properties | 201,331 | 215,794 |
| Other Property and Equipment | 22,100 | 21,401 |
| Wells and Facilities in Progress | 46,814 | 21,964 |
| Pipelines | 16,803 | 18,029 |
| **Total Property and Equipment** | 1,309,905 | 1,330,649 |
| Less: Accumulated Depreciation, Depletion and Amortization | (452,882) | (475,205) |
| **Net Property and Equipment** | 857,023 | 855,444 |
| Other Assets | 2,475 | 2,492 |
| Long-Term Derivative Instruments | 1,465 | 2,212 |
| **Total Assets** | $ 896,840 | $ 893,923 |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Accounts Payable | $ 48,221 | $ 40,712 |
| Current Maturities of Long-Term Debt | 1,859 | 764 |
| Accrued Liabilities | 35,733 | 37,207 |
| Short-Term Derivative Instruments | 12,477 | 25,025 |
| **Total Current Liabilities** | 98,290 | 103,708 |
| Long-Term Derivative Instruments | 13,486 | 7,227 |
| Senior Secured Line of Credit, Net | — | 113,785 |
| Term Loans, Net | 148,351 | — |
| Senior Notes, Net | 654,713 | 638,161 |
| Other Long-Term Debt | 8,615 | 3,409 |
| Other Deposits and Liabilities | 7,396 | 8,671 |
| Future Abandonment Cost | 9,027 | 8,736 |
| **Total Liabilities** | $ 939,878 | $ 883,697 |
| **Commitments and Contingencies (See Note 12)** | | |
| **Stockholders' Equity** | | |
| Preferred Stock, $.001 par value per share, 100,000 shares authorized and 3,987 issued and outstanding on September 30, 2017 and December 31, 2016 | $ 1 | $ 1 |
| Common Stock, $.001 par value per share, 100,000,000 shares authorized and 9,935,383 shares issued and outstanding on September 30, 2017 and 9,787,146 shares issued and outstanding on December 31, 2016. | 10 | 10 |
| Additional Paid-In Capital | 652,055 | 650,669 |
| Accumulated Deficit | (695,104) | (640,454) |
| **Total Stockholders' Equity** | (43,038) | 10,226 |
| **Total Liabilities and Stockholders' Equity** | $ 896,840 | $ 893,923 |

**See accompanying notes to the unaudited consolidated financial statements**

## REX ENERGY CORPORATION
## CONSOLIDATED STATEMENTS OF OPERATIONS
### (Unaudited, $ in Thousands, Except per Share Data)

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| **OPERATING REVENUE** | | | | |
| Natural Gas, NGL and Condensate Sales | $ 47,970 | $ 34,034 | $ 147,491 | $ 90,978 |
| Other Operating Revenue | 5 | 5 | 16 | 12 |
| **TOTAL OPERATING REVENUE** | 47,975 | 34,039 | 147,507 | 90,990 |
| **OPERATING EXPENSES** | | | | |
| Production and Lease Operating Expense | 30,574 | 26,333 | 88,882 | 76,005 |
| General and Administrative Expense | 4,617 | 5,116 | 13,444 | 15,237 |
| Loss (Gain) on Disposal of Assets | 252 | 10 | (1,707) | (4,285) |
| Impairment Expense | 11,877 | 9,563 | 16,455 | 45,344 |
| Exploration Expense | 94 | 216 | 413 | 1,954 |
| Depreciation, Depletion, Amortization and Accretion | 14,617 | 15,109 | 45,586 | 46,371 |
| Other Operating Expense | 449 | 9,899 | 331 | 10,930 |
| **TOTAL OPERATING EXPENSES** | 62,480 | 66,246 | 163,404 | 191,556 |
| **LOSS FROM OPERATIONS** | (14,505) | (32,207) | (15,897) | (100,566) |
| **OTHER INCOME (EXPENSE)** | | | | |
| Interest Expense | (13,754) | (9,646) | (35,019) | (34,115) |
| (Loss) Gain on Derivatives, Net | (18,083) | 16,866 | 684 | (8,254) |
| Other (Expense) Income | (185) | 16 | (193) | 28 |
| Debt Exchange Expense | — | (35) | — | (9,048) |
| (Loss) Gain on Extinguishments of Debt | (7) | 423 | (3,029) | 24,130 |
| **TOTAL OTHER INCOME (EXPENSE)** | (32,029) | 7,624 | (37,557) | (27,259) |
| **LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAX** | (46,534) | (24,583) | (53,454) | (127,825) |
| Income Tax Benefit | — | 8,106 | — | 5,785 |
| **NET LOSS FROM CONTINUING OPERATIONS** | (46,534) | (16,477) | (53,454) | (122,040) |
| Income From Discontinued Operations, Net of Income Taxes | — | 21,892 | — | 12,719 |
| **NET (LOSS) INCOME** | (46,534) | 5,415 | (53,454) | (109,321) |
| Preferred Stock Dividends | (598) | (613) | (1,794) | (4,441) |
| Effect of Preferred Stock Conversions | — | — | — | 72,316 |
| **NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS** | $ (47,132) | $ 4,802 | $ (55,248) | $ (41,446) |
| Earnings per common share: | | | | |
| Basic - Net Loss From Continuing Operations Attributable to Rex Energy Common Shareholders | $ (4.76) | $ (1.89) | $ (5.60) | $ (7.41) |
| Basic - Net Income From Discontinued Operations Attributable to Rex Energy Common Shareholders | — | 2.41 | — | 1.74 |
| Basic - Net (Loss) Income Attributable to Rex Energy Common Shareholders | $ (4.76) | $ 0.52 | $ (5.60) | $ (5.67) |
| Basic - Weighted Average Shares of Common Stock Outstanding | 9,906 | 9,080 | 9,859 | 7,310 |
| Diluted - Net Loss From Continuing Operations Attributable to Rex Energy Common Shareholders | $ (4.76) | $ (1.89) | $ (5.60) | $ (7.41) |
| Diluted - Net Income From Discontinued Operations Attributable to Rex Energy Common Shareholders | — | 2.41 | — | 1.74 |
| Diluted - Net Income (Loss) Attributable to Rex Energy Common Shareholders | $ (4.76) | $ 0.52 | $ (5.60) | $ (5.67) |
| Diluted - Weighted Average Shares of Common Stock Outstanding | 9,906 | 9,080 | 9,859 | 7,310 |

**See accompanying notes to the unaudited consolidated financial statements**

**REX ENERGY CORPORATION**
**CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY**
**FOR THE NINE-MONTHS ENDED SEPTEMBER 30, 2017**
**(Unaudited, in Thousands)**

| | Common Stock | | Preferred Stock | | | | |
|---|---|---|---|---|---|---|---|
| | Shares | Par Value | Shares | Par Value | Additional Paid-In Capital | Accumulated Deficit | Total Stockholders' Equity |
| BALANCE December 31, 2016 | 9,787 | $ 10 | 4 | $ 1 | $ 650,669 | $ (640,454) | $ 10,226 |
| Equity Based Compensation | — | — | — | — | 966 | — | 966 |
| Issuance of Common Stock for Debt Extinguishments | 84 | — | — | — | 467 | — | 467 |
| Issuance of Restricted Stock, Net of Forfeitures | 64 | — | — | — | — | — | — |
| Effect of Reverse Stock Split | — | — | — | — | (47) | — | (47) |
| Payment of Preferred Dividends in Arrears | — | — | — | — | — | (1,196) | (1,196) |
| Net Loss | — | — | — | — | — | (53,454) | (53,454) |
| BALANCE September 30, 2017 | 9,935 | $ 10 | 4 | $ 1 | $ 652,055 | $ (695,104) | $ (43,038) |

**See accompanying notes to the unaudited consolidated financial statements**

## REX ENERGY CORPORATION
## CONSOLIDATED STATEMENTS OF CASH FLOWS
## (Unaudited, $ in Thousands)

| | For the Nine Months Ended September 30, 2017 | 2016 |
|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES** | | |
| Net Loss | $ (53,454) | $ (109,321) |
| **Adjustments to Reconcile Net Loss to Net Cash Provided (Used) by Operating Activities** | | |
| Depreciation, Depletion, Amortization and Accretion | 45,586 | 51,471 |
| (Gain) Loss on Derivatives | (684) | 8,254 |
| Cash Settlements of Derivatives | (6,889) | 32,485 |
| Non-cash Dry Hole Expense | 13 | 872 |
| Equity-based Compensation Expense | 970 | 1,931 |
| Impairment Expense | 16,455 | 48,887 |
| Amortization of net Bond Discount and Deferred Debt Issuance Costs | — | 881 |
| Non-cash Interest Expense related to Debt Restructurings and Exchanges | 18,873 | 14,270 |
| Loss (Gain) on Extinguishments of Debt | 3,029 | (24,213) |
| Gain on Sale of Assets | (1,707) | (34,820) |
| Other Non-cash Expense | 733 | 61 |
| **Changes in operating assets and liabilities** | | |
| Accounts Receivable | 5,311 | (2,580) |
| Taxes Receivable | 163 | — |
| Inventory, Prepaid Expenses and Other Assets | (2,234) | 2,374 |
| Accounts Payable and Accrued Liabilities | (1,485) | (7,781) |
| Other Assets and Liabilities | (2,275) | (1,244) |
| **NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES** | 22,405 | (18,473) |
| **CASH FLOWS FROM INVESTING ACTIVITIES** | | |
| Proceeds from the Sale of Oil and Gas Properties, Prospects and Other Assets | 31,607 | 40,809 |
| Proceeds from Joint Venture for Reimbursement of Capital Costs | — | 19,461 |
| Acquisitions of Undeveloped Acreage | (2,988) | (6,302) |
| Capital Expenditures for Development of Oil & Gas Properties and Equipment | (79,101) | (48,640) |
| **NET CASH (USED IN) PROVIDED BY INVESTING ACTIVITIES** | (50,482) | 5,328 |
| **CASH FLOWS FROM FINANCING ACTIVITIES** | | |
| Proceeds from Long-Term Debt and Line of Credit | 183,000 | 55,400 |
| Repayments of Long-Term Debt and Line of Credit | (145,170) | (35,230) |
| Repayments of Loans and Other Notes Payable | (869) | (568) |
| Debt Issuance Costs | (8,151) | (5,024) |
| Payment of Preferred Dividends in Arrears | (1,196) | — |
| **NET CASH PROVIDED BY FINANCING ACTIVITIES** | 27,614 | 14,578 |
| **NET (DECREASE) INCREASE IN CASH** | (463) | 1,433 |
| **CASH – BEGINNING** | 3,697 | 1,091 |
| **CASH – ENDING** | $ 3,234 | $ 2,524 |
| **CASH AND CASH EQUIVALENTS ATTRIBUTABLE TO CONTINUING OPERATIONS** | $ 3,234 | $ 2,524 |
| **SUPPLEMENTAL DISCLOSURES** | | |
| Interest Paid, net of capitalized interest | $ 13,961 | $ 25,833 |
| Cash (Received) Paid for Income Taxes | (163) | 29 |
| Capital Expenditures for Development of Oil & Gas Properties and Equipment Attributable to Discontinued Operations | — | 1,341 |
| **NON-CASH ACTIVITIES** | | |
| Change in fair value of contingent consideration receivable - sale of Illinois Basin | $ (1,987) | $ (1,166) |
| Proceeds held in Escrow - non-cash component of Gain on Sale of Assets | 5,000 | — |
| Increase (Decrease) in Accounts Payable and Accrued Liabilities for Capital Expenditures | 6,929 | (5,912) |
| Increase in Other Long Term Debt - Capital Lease Equipment Financing | 8,120 | 816 |
| Decrease in Senior Notes carrying value net of Issuance Costs, Deferred Gain on Exchanges, and Net Premium / Discount due to Debt to Equity Conversions | (879) | (46,248) |
| Decrease in Bond Interest Payable due to Debt to Equity Conversions | (12) | (870) |
| Increase in Common Stock outstanding due to Debt to Equity Conversions | 467 | 16,916 |

**See accompanying notes to the unaudited consolidated financial statements**

## 1. BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION

Rex Energy Corporation, together with our subsidiaries (the “Company”), is an independent natural gas, natural gas liquid (“NGL”) and condensate company with operations currently focused in the Appalachian Basin. We are focused on Marcellus Shale, Utica Shale and Upper Devonian Shale drilling and exploration activities. We pursue a balanced growth strategy of exploiting our sizable inventory of high potential exploration drilling prospects while actively seeking to acquire complementary oil and natural gas properties.

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and include the accounts of all of our wholly owned subsidiaries. We report our interests in natural gas, NLG and condensate properties using the proportional consolidation method of accounting. All intercompany balances and transactions have been eliminated. Unless otherwise indicated, all references to “Rex Energy Corporation,” “our,” “we,” “us” and similar terms refer to Rex Energy Corporation and its subsidiaries together. In preparing the accompanying Consolidated Financial Statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies.

The interim Consolidated Financial Statements of the Company are unaudited and contain all adjustments (consisting primarily of normal recurring accruals) necessary for a fair statement of the results for the interim periods presented. Actual results may differ from those estimates and results for interim periods are not necessarily indicative of results to be expected for a full year or for previously reported periods due in part, but not limited to, the volatility in prices for crude oil, NGLs and natural gas, future impact of financial derivative instruments, interest rates, estimates of reserves, drilling risks, geological risks, transportation restrictions, the timing of acquisitions, product demand, market consumption, interruption in production, our ability to obtain additional capital, and the success of oil, NGL and natural gas recovery techniques.

Certain amounts and disclosures have been condensed or omitted from these Consolidated Financial Statements pursuant to the rules and regulations of the Securities and Exchange Commission. Therefore, these interim financial statements should be read in conjunction with the audited Consolidated Financial Statements and related notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2016.

*Reverse Stock Split*

On May 12, 2017, we effected a one-for-ten reverse stock split. As a result of the reverse stock split, each ten shares of our common stock automatically combined into and became one share of our common stock. Any fractional shares which would have otherwise been due as a result of the reverse split were rounded up to the nearest whole share. As a result of the reverse stock split, we reduced the issued number of common shares from 99.0 million to 9.9 million. The reverse stock split automatically and proportionately adjusted, based on the one-for-ten split ratio, all issued and outstanding shares of our common stock, as well as common stock underlying stock options, warrants and other derivative securities outstanding at the time of the effectiveness of the reverse stock split. The exercise price on outstanding equity based-grants proportionately increased, while the number of shares available under our equity-based plans also was proportionately reduced. Share and per share data for the periods presented reflect the effects of this reverse stock split. References to numbers of shares of common stock and per share data in the accompanying financial statements and notes thereto have been adjusted to reflect the reverse stock split on a retroactive basis.

*Discontinued Operations*

In 2016, we divested all of our Illinois Basin assets and operations. The sale closed in August 2016, with an effective date of July 1, 2016. As a result of this transaction, the 2016 results of operations of our Illinois Basin operations have been classified as Discontinued Operations in the accompanying Consolidated Statements of Operations for the year ended December 31, 2016.

Unless otherwise noted, all disclosures and tables reflect the results of continuing operations and exclude any assets, liabilities or results from our discontinued operations. For additional information see Note 3, *Discontinued Operations/Assets Held for Sale*, to our Consolidated Financial Statements.

## 2. FUTURE ABANDONMENT COST

Future abandonment costs are recognized as obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the asset. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which the natural gas or oil well is acquired or drilled. The future abandonment cost is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the natural gas or oil well is sold, at which time the liability is reversed. If the fair value of a recorded future abandonment cost changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost.

Accretion expense totaled $0.5 million and $1.5 million for the three and nine months ended September 30, 2017, respectively, and $0.1 million and $0.5 million for the three and nine months ended September 30, 2016, respectively. These amounts are recorded as depreciation, depletion, amortization and accretion ("DD&A") expense on our Consolidated Statements of Operations. We account for future abandonment costs that relate to wells that are drilled jointly based on our working interest in those wells.

| ($ in Thousands) | | September 30, 2017 |
|---|---|---|
| Beginning Balance at January 1, 2017 | $ | 9,865 |
| Future Abandonment Obligation Incurred | $ | 1,069 |
| Future Abandonment Obligation Settled | $ | (2,204) |
| Future Abandonment Obligation Cancelled or Sold | $ | (262) |
| Future Abandonment Obligation Revision of Estimated Obligation | $ | 57 |
| Future Abandonment Obligation Accretion Expense | $ | 1,479 |
| Total Future Abandonment Cost[1] | $ | 10,004 |

1 Includes approximately $1.0 million of short-term future abandonment costs, which are classified as Accrued Liabilities on our Consolidated Balance Sheet.

### 3. DISCONTINUED OPERATIONS/ASSETS HELD FOR SALE

*Illinois Basin Operations*

On June 14, 2016, we, through our wholly owned subsidiaries, Penntex Resources Illinois, LLC, Rex Energy I, LLC, Rex Energy IV, LLC, Rex Energy Marketing, LLC, R. E. Ventures Holdings, LLC, and Rex Energy Operating Corp. (collectively, "Rex"), entered into a Purchase and Sale Agreement (the "Agreement") with Campbell Development Group, LLC ("Campbell"). Pursuant to the Agreement, Campbell agreed to purchase, subject to certain parameters and provisions for adjustment customary for transactions of this type, all of our oil and gas-related properties and assets, both operated and non-operated, in the Illinois Basin on an as-is, where-is basis. Closing occurred on August 18, 2016, with an effective date for the transaction of July 1, 2016. We received a purchase deposit of $2.5 million from Campbell in June 2016 and received the additional proceeds of approximately $38.0 million during the third and fourth quarters of 2016. An addendum executed in conjunction with the Agreement allows for us to receive from Campbell potential additional proceeds of up to $9.9 million, in installments of $0.9 million per quarter, over the period beginning with the quarter ended December 31, 2016, and ending with the quarter ending June 30, 2019. For the proceeds to become payable by Campbell in any of the eleven individual quarters, the average spot price of West Texas Intermediate ("WTI") as published by the New York Mercantile Exchange must be in excess of the amount shown in the table below for the applicable quarter. As of September 30, 2017, the first four of the eleven quarterly measurement periods have expired with the calculated average spot price of WTI below the threshold price stipulated in the agreement. Consequently, we did not receive any additional proceeds related to those measurement periods. As of September 30, 2017, we have the potential to receive up to $6.3 million of additional proceeds, during the seven remaining measurement periods. For additional information, see Note 8, *Derivative Instruments and Fair Value Measurements*, to our Consolidated Financial Statements.

| Calendar Quarter Ending | | West Texas Intermediate ("WTI") Average Price per Bbl (a) |
|---|---|---|
| 9/30/2017 | $ | 60.25 |
| 12/31/2017 | $ | 60.75 |
| 3/31/2018 | $ | 61.25 |
| 6/30/2018 | $ | 61.75 |
| 9/30/2018 | $ | 62.25 |
| 12/31/2018 | $ | 62.75 |
| 3/31/2019 | $ | 63.25 |
| 6/30/2019 | $ | 63.75 |

(a) Calculated as the sum of the closing spot price of the West Texas Intermediate of the New York Mercantile Exchange for each day during the quarter (excluding weekends and holidays), divided by the number of days on which those prices are published (excluding weekends and holidays).

Included in the sale were approximately 76,000 net acres in Illinois, Indiana and Kentucky and production of approximately 1,700 net barrels per day. The sale transaction resulted in a full divestiture of our Illinois Basin assets, and an exit from our Illinois Basin operations. As of September 30, 2017 and December 31 2016, we had no remaining assets or liabilities related to our former

Illinois Basin operations. The results of operations of our Illinois Basin operations are reported as Discontinued Operations for the three and nine months ended September 30, 2016, in our Consolidated Statements of Operations.

Summarized financial information for Discontinued Operations related to our Illinois Basin operations is set forth in the tables below, and does not reflect the costs of certain services provided. Such indirect costs, which were not allocated to the Discontinued Operations, were for services, including legal counsel, insurance, external audit fees, payroll processing, certain human resource services and information technology systems support. The sale of our Illinois assets and operations does not include any of our derivative contracts or positions related to our Illinois Basin revenues or production. No derivative positions or activity has been attributed to or included in Discontinued Operations for the three and nine month periods ended September 30, 2017 and 2016.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| ($ in Thousands) | 2017 | 2016 | 2017 | 2016 |
| **Revenues:** | | | | |
| Oil Sales | $ — | $ 69 | $ — | $ 11,283 |
| **Total Operating Revenue** | — | 69 | — | 11,283 |
| **Costs and Expenses:** | | | | |
| Production and Lease Operating Expense | — | 261 | — | 10,987 |
| General and Administrative Expense | — | 33 | — | 1,471 |
| Gain on Disposal of Assets | — | (30,491) | — | (30,535) |
| Impairment Expense | — | — | — | 3,543 |
| Exploration Expense | — | — | — | 143 |
| Depreciation, Depletion, Amortization and Accretion | — | 18 | — | 5,100 |
| Interest Expense | — | 1 | — | 4 |
| Other Expense | — | 1 | — | (1) |
| **Total Costs and Expenses** | — | (30,177) | — | (9,288) |
| **Income From Discontinued Operations, Before Income Taxes** | — | 30,246 | — | 20,571 |
| Income Tax (Expense) Benefit | — | (8,354) | — | (7,852) |
| **Income From Discontinued Operations, Net of Taxes** | $ — | $ 21,892 | $ — | $ 12,719 |
| **Production:** | | | | |
| Crude Oil (Bbls) | — | 1,688 | — | 310,408 |

**4. BUSINESS AND OIL AND GAS PROPERTY DISPOSITIONS**

*Benefit Street Partners, LLC*

On March 1, 2016, we entered into a joint exploration and development agreement with an affiliate of Benefit Street Partners, LLC (“BSP”) to jointly develop 58 specifically designated wells in our Moraine East and Warrior North operated areas. BSP agreed to participate in and fund 15.0% of the estimated well costs for 16 designated wells in Butler County, Pennsylvania, all of which have already been drilled, completed, placed in sales and paid for by BSP. BSP also agreed to participate in and fund 65.0% of the estimated well costs for six designated wells in Warrior North, Ohio, all of which have been drilled, completed, placed in sales and paid for by BSP. BSP also has the option to participate in the development of 36 additional wells and would fund 65.0% of the estimated well costs for the designated wells in return for a 65.0% working interest. To date, BSP has exercised its option to participate in 23 of these additional wells. Total consideration for this transaction could be up to $175.0 million with approximately $134.0 million committed as of September 30, 2017. BSP has paid approximately $128.3 million for its interest in elected wells as of September 30, 2017. The remainder of the proceeds will be received as additional wells are drilled to total depth or placed in sales. BSP earns an assignment of 15%-20% working interest in acreage located within each of the units in which it participates. As of September 30, 2017, 42 of the 45 committed wells were in line and producing and three wells were drilled and awaiting completion.

The BSP transaction constitutes a pooling of assets in a joint undertaking to develop these specific properties for which there is substantial uncertainty about the ability to recover the costs applicable to our interest in the properties. Under the terms of the agreement, we hold a substantial obligation for future performance, which may not be proportionally reimbursed by BSP. Due to the uncertainty that exists on the recoverability of costs associated with our retained interest, proceeds received from BSP are considered a recovery of costs and no gain or loss is recognized.

*Diversified Oil & Gas, LLC*

On May 20, 2016, we entered into a Purchase and Sale Agreement (the “PSA”) with Diversified Oil and Gas, LLC (“DOG”). Pursuant to the PSA, DOG purchased all of our conventional operated oil and gas-related properties and related pipeline assets located in Pennsylvania and assumed all future abandonment liability associated with the assets. Closing occurred on May 20, 2016, with an effective date for the transaction of May 1, 2016. We received proceeds at closing of approximately $0.1 million. Included in the sale were approximately 300 wells, pipelines and support equipment. The sale of well properties generated approximately $4.6 million of gain in the second quarter of 2016 due to the elimination of our future abandonment liability associated with wells and pipelines sold to DOG. The gain, which is included in *Gain on Disposal of Assets* on our Consolidated Statement of Operations, is reported net of approximately $0.2 million of uncollectible accounts receivable written off in conjunction with the sale.

*Illinois Basin Operations*

As described in Note 3, *Discontinued Operations/Assets Held for Sale*, we sold our Illinois Basin assets and operations pursuant to a purchase and sale agreement with Campbell in August 2016.

*Sale of Warrior South Assets*

On January 11, 2017, we, together with MFC Drilling, Inc., and ABARTA Oil & Gas Co., Inc. sold substantially all of our jointly owned oil and gas interests in Noble, Guernsey, and Belmont Counties, Ohio, to Antero Resources Corporation. These interests comprised our Warrior South development area. The effective date for the transaction is October 1, 2016. The sales agreement includes representations, warranties, covenants and agreements as well as various provisions for purchase price and post-closing adjustments customary for transactions of this type. Total consideration for the transaction was approximately $50.0 million, with approximately $29.1 million net to us, subject to customary closing and post-closing adjustments. We received approximately $24.1 million of proceeds on January 11, 2017. Approximately $5.0 million of the total proceeds due to us will be held in escrow and will be released in January 2018, net of post-closing adjustments. The proceeds held in escrow are classified as accounts receivable on our Consolidated Balance Sheet as of September 30, 2017. The sale of assets resulted in a gain on disposal of assets of approximately $1.8 million in January 2017. This gain includes the additional proceeds held in escrow, which we anticipate receiving in January 2018. The sale of assets included 14 gross wells with associated production of 15 Mmcfe/d, with 9 Mmcfe/d net to us, and approximately 6,200 gross acres, with 4,100 acres net to us. This acreage was considered non-core to us. We used the proceeds from the transaction to pay down our revolving line of credit and for general corporate purposes.

## 5. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board (the “FASB”) issued ASU 2014-09, *Revenue from Contracts with Customers*. The amendments in this ASU affects any entity using U.S. GAAP that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards. This ASU will supersede the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance. The core principle of the guidance in ASU 2014-09 is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance provides a five step process to be applied in evaluating contracts under the new standard:

1) Identify the contract(s) with a customer.
2) Identify the performance obligations in the contract.
3) Determine the transaction price.
4) Allocate the transaction price to the performance obligations in the contract.
5) Recognize revenue when (or as) the entity satisfies a performance obligation.

Subsequent to the issuance of ASU 2014-09, the FASB issued several additional Accounting Standards Updates to clarify implementation guidance, provide guidance regarding principal vs. agent considerations and identifying performance obligations, provide narrow-scope improvements, and provide additional disclosure guidance. ASU 2014-09 is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with the cumulative effect of applying the new standard recognized as an adjustment to retained earnings in the most current period presented in the financial statements. The standard is effective for annual reporting periods, and interim periods within that reporting period, beginning after December 15, 2017. Early adoption is not permitted. In preparation for adopting the standard, we are reviewing our contracts and revenue sources to identify performance obligations, pricing structures, or other contractual elements that may have impacts to our consolidated financial statements once the standard is adopted. We have reviewed a substantial portion of our revenue contracts; however; the evaluation is on-going and we have not finalized any estimates of potential impacts. For the evaluations we have completed, we do not expect the standard would result in materially different results to the timing or amounts of our revenue recognition. We will adopt the new standard on January 1, 2018 using a modified retrospective approach with a cumulative adjustment to retained earnings as necessary.

In February 2016, the FASB issued ASU 2016-02, *Leases*. Under the new guidance, lessees will be required to recognize the following for all leases (with the exception of short-term leases) at the commencement date:

- A lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and
- A right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term.

Public business entities are required to apply the amendment of this update for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted for all public business entities. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The modified retrospective approach would not require any transition accounting for leases that expired before the earliest comparative period presented. We are currently evaluating the potential impact of this standard on our results of operations and internal control environment.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*. The amendments in the update provide guidance regarding the presentation in the statement of cash flows of eight specific cash flow disclosure issues:

- debt prepayment or debt extinguishment costs;
- settlement of zero-coupon debt instruments or other instruments with coupon rates that are insignificant in relation to the effective interest rate of borrowing;
- contingent consideration payments made after a business combination;
- proceeds from the settlement of insurance claims;
- proceeds from the settlement of corporate-owned life insurance policies;
- distributions received from equity method investees;
- beneficial interest in securitization transactions; and
- separately identifiable cash flows and application of the Predominance Principle.

Public business entities are required to apply the amendments of this update for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. The amendments should be applied using a retrospective transition method to each period presented. We are currently evaluating this guidance to assess its impact on our current cash flow reporting processes.

In May 2017, the FASB issued ASU 2017-09, *Stock Compensation - Scope of Modification Accounting*, which provides guidance about the types of changes to terms or conditions of a share-based payment award that would require an entity to apply modification accounting. The new guidance is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted. The amendments in this update should be applied prospectively to an award modified on or after the adoption date.

**6. CONCENTRATIONS OF CREDIT RISK**

By using derivative instruments to hedge exposure to changes in commodity prices, we are exposed to credit risk and market risk. Credit risk is the failure of the counterparties to perform under the terms of the derivative contract. When the fair value of the derivative is positive, the counterparty owes us, which creates repayment risk. We minimize the credit or repayment risk in derivative instruments by entering into transactions with high-quality counterparties. Our counterparties are investment grade financial institutions (see Note 7, *Long-Term Debt*, to our Consolidated Financial Statements). We have a master netting agreement in place with our counterparties that provides for the offsetting of payables against receivables from separate derivative contracts. None of our derivative contracts have a collateral provision that would require funding prior to the scheduled cash settlement date. For additional information, see Note 8, *Derivative Instruments and Fair Value Measurements*, to our Consolidated Financial Statements.

We also depend on a relatively small number of purchasers for a substantial portion of our revenue. For the nine months ended September 30, 2017, approximately 95.3% of our commodity sales came from five purchasers, with the largest single purchaser accounting for 50.0% of commodity sales. We believe the growth in our Appalachian estimated proved reserves will help us to minimize our future risks by diversifying our ratio of condensate and gas sales as well as the quantity of purchasers.

## 7. LONG-TERM DEBT

*Term Loan*

On April 28, 2017 (the "Effective Date"), we entered into a term loan agreement ("Term Loan") with Angelo, Gordon Energy Servicer, LLC ("AGES"), as administrative agent, AGES, as collateral agent (in such capacity, the "Collateral Agent"), Macquarie Bank Limited, as issuing bank (in such capacity, the "Issuing Bank"), and the lenders from time to time party thereto. The Term Loan replaced our prior amended and restated senior secured revolving credit agreement with Royal Bank of Canada, as Administrative Agent, and the lenders from time to time party thereto (the "Prior Credit Agreement"). The Term Loan provides for a $143,500,000 secured term loan facility (the "Term Facility") and a $156,500,000 secured delayed draw term loan facility (the "Delayed Draw Term Facility"), which includes a letter of credit sub-facility (the "Letter of Credit Sub-facility"). The proceeds of the initial loans under the Term Loan were used to refinance the loans then outstanding under the Prior Credit Agreement and payment of fees and expenses related thereto; the proceeds of future loans under the Delayed Draw Term Facility may be used for cash collateralizing letters of credit under the Letter of Credit Sub-facility and general corporate purposes. The maximum commitments of the lenders under the Term Loan are currently limited to $300,000,000. Amounts borrowed and repaid may not be re-borrowed. The maturity date for the loans under the Term Facility and the loans drawn under the Delayed Draw Term Facility is the earlier of (a) April 28, 2021 and (b) the date that is six months prior to the maturity of our 1.00/8.00% Senior Secured Second Lien Notes due 2020 (the "Second Lien Notes") unless less than $25,000,000 in aggregate principal amount of Second Lien Notes are then outstanding and no Event of Default (as defined in the Term Loan) exists on such date. The commitments under the Delayed Draw Term Facility expire if not drawn prior to the earlier of (a) April 28, 2018 (which date may be extended for one year with lender consent) and (b) the date upon which we terminate such commitments. As of September 30, 2017, we had $155.5 million in borrowings outstanding and approximately $32.2 million in outstanding undrawn letters of credit. We incurred approximately $3.5 million in debt issuance costs and $4.3 million in original issue discount ("OID") related to the initial Term Loan borrowing. We incurred an additional $0.4 million in OID related to the Delayed Draw Term Facility. From April 28, 2017 through September 30, 2017, we amortized $0.4 million of debt issuance costs and $0.5 million of OID. The amortization of debt issuance costs and OID are reported as Interest Expense in our Consolidated Statement of Operations.

Borrowings under the Term Loan bear interest at a rate per annum equal to the "Adjusted LIBO Rate" (subject to a 1.00% floor) plus an 8.75% per annum margin. The "Adjusted LIBO Rate" is equal to the product of the three month LIBOR rate multiplied by the statutory reserve rate. Upon the occurrence and continuance of an Event of Default all outstanding loans shall bear interest at a rate equal to 4.00% per annum plus the then-effective rate of interest. Interest is payable on the last business day of each March, June, September and December. Under the Term Loan, we will pay a 3.5% commitment fee on any unused portion of the Delayed Draw Term Facility.

The Term Loan requires us to prepay the loans with 100% of the net cash proceeds received from certain asset sales, swap terminations, incurrences of borrowed money indebtedness, casualty events and equity issuances, subject to certain exceptions and specified reinvestment rights. Prepayments based on 75% of excess cash flow, ("excess cash flow" as defined in the Term Loan agreement represents EBITDAX less capital expenditures, cash payments for interest, cash payments for income taxes, and adjustments for certain non-cash expenses) are required until no more than $287,950,000 in aggregate principal amount of Second Lien Notes remain outstanding, at which time, prepayments based on 50% of excess cash flow will be required. Prepayments (including mandatory prepayments), terminations, refinancing, reductions and accelerations under the Term Loan are subject to a yield maintenance amount equal to the interest which would have accrued on such prepaid, terminated, refinanced, reduced or accelerated amount during the period beginning on the date of such prepayment, termination, refinancing, reduction or acceleration and ending on the date that is 30 months after the Effective Date and a call protection amount (a) during the period commencing on the Effective Date and ending on the date that is 30 months thereafter, in an amount equal to 3.0% of such prepaid, terminated, refinanced, reduced or accelerated amount and (b) during the period commencing on the date that is 30 months and one day after the Effective Date and ending on the date that is 36 months after the Effective Date, an amount equal to 1.0% of such prepaid, terminated, refinanced, reduced or accelerated amount.

The Term Loan contains covenants that restrict our ability to, among other things, materially change the nature of our business, make dividend payments, enter into transactions with affiliates, create or acquire additional subsidiaries, incur indebtedness, sell assets, make loans to others, make investments, enter into mergers, incur liens, and enter into agreements regarding swap and other derivative transactions.

The Term Loan also requires that we comply with the following financial covenants: (1) as of the last day of any fiscal quarter ending on or after December 31, 2017, the PDP Coverage Ratio (as defined in the Term Loan) will not be less than 1.65 to 1.00; (2) as of the last day of any fiscal quarter ending on or after March 31, 2017, the ratio of Net Senior Secured Debt (as defined in the Term Loan) as of such date to EBITDAX (as defined in the Term Loan) for the period of four fiscal quarters then ending on such day will not be greater than 3.25 to 1.00 (provided that EBITDAX for the four fiscal quarters ending on (i) March 31, 2017 shall be EBITDAX for the fiscal quarter then ending multiplied by four and (ii) June 30, 2017 shall be EBITDAX for the two fiscal quarters then ending multiplied by two); and (3) as of the last day of any fiscal quarter ending on or after September 30, 2017, the ratio of EBITDAX for the four fiscal quarters then ending to cash interest expense will not be less than (i) 1.00 to 1.00 for any fiscal quarter ending on or before September 30, 2017 and (ii) 1.30 to 1.00 for each fiscal quarter thereafter. As of September 30, 2017, our Net Senior Secured Debt to EBITDAX Ratio was 2.85 to 1.00 and EBITDAX to Cash Interest Expense was 2.88 to 1.00.

Our obligations under the Credit Agreement may be accelerated upon the occurrence of an Event of Default (as such term is defined in the Term Loan). Events of Default include customary events for a financing agreement of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change of Control (as such term is defined in the Term Loan).

Obligations under the Term Loan are secured by mortgages on our oil and gas properties. In connection with the Term Loan, we, including our wholly owned subsidiaries, Rex Energy I, LLC, Rex Energy Operating Corp., PennTex Resources Illinois, Inc., Rex Energy IV, LLC, and R.E. Gas Development, LLC (collectively, the "Guarantors" and together with us, the "Grantors"), entered into an amended and restated guaranty and collateral agreement, dated as of April 28, 2017, in favor of the Collateral Agent for the lenders from time to time party to the Term Loan, the secured swap parties and the Issuing Bank (the "Guaranty and Collateral Agreement"). Pursuant to the Guaranty and Collateral Agreement, each of the Guarantors, jointly and severally, guaranteed the prompt and complete payment of our obligations under the Term Loan. In addition, each Grantor granted, as security for the prompt and complete payment and performance when due of such Grantor's obligations, a security interest in substantially all of its assets, including equity interests in other Guarantors, as applicable.

*Senior Secured Line of Credit*

On April 28, 2017, we terminated our senior secured line of credit under the Prior Credit Agreement. A portion of the proceeds of the initial loans under the Term Loan were used to refinance loans outstanding under the Prior Credit Agreement. In conjunction with the retirement of the Prior Credit Agreement, we expensed $3.4 million of associated unamortized debt issuance costs, included in *Loss on Extinguishments of Debt* in our Consolidated Statement of Operations. We had $117.7 in million borrowings outstanding under the Prior Credit Agreement as of December 31, 2016.

*Senior Notes*

On March 31, 2016, we completed an exchange offer and consent solicitation related to our 8.875% Senior Notes due 2020 (the "2020 Notes") and 6.25% Senior Notes due 2022 (the "2022 Notes" and, together with the 2020 Notes, the "Existing Notes"). We offered to exchange (the "Exchange") any and all of the Existing Notes held by eligible holders for up to (i) $675.0 million aggregate principal amount of our new Second Lien Notes and (ii) 10.1 million shares of our common stock (the "Shares"). We accounted for these transactions as troubled debt restructurings. As a result of the troubled debt exchanges, the future undiscounted cash flows of the Second Lien Notes are greater than the net carrying value of the Existing Notes. As such, no gain has been recognized within our GAAP basis financial statements and a new effective interest rate has been established. See Note 9, *Income Taxes*, to our Consolidated Financial Statements, for information regarding the tax treatment and impact of the Exchange for federal and state income tax purposes.

In exchange for $324.0 million in aggregate principal amount of the 2020 Notes, representing approximately 92.6% of the outstanding aggregate principal amount of the 2020 Notes, and $309.1 million in aggregate principal amount of the 2022 Notes, representing approximately 95.1% of the outstanding aggregate principal amount of the 2022 Notes, we issued (i) $633.2 million aggregate principal amount of Second Lien Notes and (ii) 8.4 million Shares, which had a fair value of $6.5 million upon issuance. An additional $0.5 million aggregate principal amount of Second Lien Notes were issued to holders who were ineligible to accept Shares. In addition, upon closing, we paid in cash accrued and unpaid interest on the Existing Notes accepted in the Exchange from the applicable last interest payment date totaling approximately $12.8 million. The remaining Existing Notes will continue to accrue interest at their historical rates. The Second Lien Notes will bear interest at a rate of 1.0% per annum for the first three semi-annual interest payments after issuance and 8.0% per annum thereafter, payable in cash. Interest payments are due on April 1 and October 1 of each year, beginning October 1, 2016 and ending October 1, 2020. In connection with the Exchange, we incurred approximately $9.1 million in third-party debt issuance costs during the year ended December 31, 2016. These costs were recorded as Debt Exchange Expense in our Consolidated Statement of Operations.

Following the completion of the Exchange, we entered into debt-for equity exchanges during the remainder of 2016, with certain holders of our Existing Notes, as well as holders of our Second Lien Notes, in exchange for unrestricted shares of our common stock. These exchanges resulted in the retirement of $27.7 million in aggregate principal amount of our remaining Existing Notes and $45.7 million in aggregate principal amount of our outstanding Second Lien Notes, in exchange for the issuance of a total of approximately 22.7 million shares of unrestricted common stock during the year ended December 31, 2016. In the nine months ended September 30, 2017, we completed debt-for equity exchanges with certain holders of our Existing Notes. These exchanges resulted in the retirement of approximately $0.9 million in aggregate principal amount of our remaining Existing Notes, in exchange for approximately 0.1 million shares of unrestricted common stock. The exchanged notes were subsequently cancelled, resulting in a gain for the nine months ended September 30, 2017 of approximately $0.4 million, presented as Gain on Extinguishments of Debt in our Consolidated Statements of Operations.

We may redeem, at specified redemption prices, some or all of the Second Lien Notes at any time on or after April 1, 2018. We may also redeem up to 35% of the Second Lien Notes using the proceeds of certain equity offerings completed before April 1, 2018. If we sell certain of our assets or experience specific kinds of changes in control, we may be required to offer to purchase the Existing Notes and the Second Lien Notes from the holders.

Our Existing Notes and Second Lien Notes (collectively, the "Senior Notes") are recorded as Senior Notes, Net of Issuance Costs and Deferred Gain on Exchanges on our Consolidated Balance Sheets.

The Senior Notes are governed by indentures (the "Indentures"), which contain affirmative and negative covenants that are customary for instruments of this nature, including restrictions or limitations on our ability to incur additional debt, pay dividends, purchase or redeem stock or subordinated indebtedness, make investments, create liens, sell assets, merge with or into other companies or transfer substantially all of our assets, unless those actions satisfy the terms and conditions of the Indentures or are otherwise excepted or permitted. Certain of the limitations in the Indentures, including our ability to incur debt, pay dividends or make other restricted payments, become more restrictive in the event our ratio of consolidated cash flow to fixed charges for the most recent trailing four quarters (the "Fixed Charge Coverage Ratio") is less than 2.25 to 1.00. As of September 30, 2017, our Fixed Charge Coverage Ratio was 1.24 to 1.00. We expect our Fixed Charge Coverage Ratio to improve based on our projections of decreased interest expense related to the Second Lien Notes, increased production and improved price realizations. As of September 30, 2017, we were limited to incurring approximately $134.9 million of additional debt due to our Fixed Charge Coverage Ratio. The Indentures also contain customary events of default. In certain circumstances, the individual trustees under the Indentures or the holders of the Senior Notes may declare all outstanding Senior Notes to be due and payable immediately.

As of September 30, 2017 and December 31, 2016, we had recorded on our Consolidated Balance Sheets approximately $15.1 million and $3.6 million, respectively, of net premium/discounts related to the Senior Notes. The amortization of our net premium during the three and nine months ended September 30, 2017, which follows the effective interest method, was approximately $3.9 million and $11.5 million, respectively, and was recorded as a credit to Interest Expense on our Consolidated Statements of Operations. Interest is payable semi-annually on our Existing Notes. Interest on the 2020 Notes is paid at a rate of 8.875% per annum on June 1 and December 1 of each year, while interest on the 2022 Notes is paid at a rate of 6.25% per annum on February 1 and August 1 of each year. Total interest expense for the three months ended September 30, 2017 is comprised of non-cash amortization of $6.7 million, cash interest payments of $5.5 million and an increase in accrued interest of $1.6 million. Total interest expense for the nine months ended September 30, 2017 is comprised of non-cash amortization of $19.6 million, cash interest payments of $13.9 million and an increase in accrued interest of $1.5 million.

| | September 30, 2017 | | | | |
|---|---|---|---|---|---|
| | **Principal** | **Unamortized net Premium / Discount** | **Unamortized Debt Issuance Costs** | **Unamortized Deferred Gain on Debt Restructurings** | **Net Carrying Value** |
| *Term Loans, Net* | | | | | |
| Term Loan Draw - due April 2020 | $ 155,500 | $ (4,124) | $ (3,025) | $ — | $ 148,351 |
| *Senior Notes, Net* | | | | | |
| 8.875% Senior Notes due 2020 | $ 7,333 | $ 21 | $ (86) | $ — | $ 7,268 |
| 6.25% Senior Notes due 2022 | 5,363 | — | (70) | — | 5,293 |
| 1% / 8% Second Lien Senior Notes due 2020 | 587,606 | (15,149) | 36,540 | 33,155 | 642,152 |
| | $ 600,302 | $ (15,128) | $ 36,384 | $ 33,155 | $ 654,713 |

| | |
|---|---|
| *Other Long-Term Debt* | |
| Long-Term Capital Leases - Equipment Financing | |
| Due March, 2021 | $ 666 |
| Due June, 2021 | 1,495 |
| Due September, 2021 | 1,650 |
| Due May, 2022 | 6,663 |
| Total Capital Lease Obligations | $ 10,474 |
| Less: Current Portion of Capital Leases | (1,859) |
| | $ 8,615 |

The weighted average interest rate on borrowed balances under the Term Loan for the three and nine months ended September 30, 2017 was approximately 10.2% and 10.1%, respectively. The weighted average interest rate on the Senior Credit Facility for the three and nine months ended September 30, 2017 was not applicable during the three month period and approximately 4.5% in the nine-month period. The average interest rate on our capital leases for the three and nine months ended September 30, 2017 was approximately 21.4% and 18.3%, respectively.

| | December 31, 2016 | | | | |
|---|---|---|---|---|---|
| | Principal | Unamortized net Premium / Discount | Unamortized Debt Issuance Costs | Unamortized Deferred Gain on Debt Restructurings | Net Carrying Value |
| *Senior Secured Line of Credit, Net* | | | | | |
| Revolving Senior Credit Facility | $ 117,670 | $ — | $ (3,885) | $ — | $ 113,785 |
| *Senior Notes, Net* | | | | | |
| 8.875% Senior Notes due 2020 | $ 7,573 | $ 26 | $ (107) | $ — | $ 7,492 |
| 6.25% Senior Notes due 2022 | 5,648 | — | (82) | — | 5,566 |
| 1% / 8% Second Lien Senior Notes due 2020 | 587,956 | (3,627) | 8,098 | 32,676 | 625,103 |
| | $ 601,177 | $ (3,601) | $ 7,909 | $ 32,676 | $ 638,161 |
| *Other Long-Term Debt* | | | | | |
| Long-Term Capital Leases and Other Notes Payable- Equipment Financing | | | | | |
| Due March, 2021 | | | | | $ 760 |
| Due June, 2021 | | | | | 2,225 |
| Due September, 2021 | | | | | 1,174 |
| Total Capital Lease Obligations | | | | | $ 4,159 |
| Other Notes Payable | | | | | 14 |
| Total Capital Lease and Note Payable Obligations | | | | | $ 4,173 |
| Less: Current Portion of Capital Leases and Other Notes Payable | | | | | (764) |
| | | | | | $ 3,409 |

The following is the principal maturity schedule for debt outstanding as of September 30, 2017:

| | |
|---|---|
| 2017 | $ 436 |
| 2018 | 1,926 |
| 2019 | 2,252 |
| 2020 | 753,075 |
| 2021 | 2,462 |
| Thereafter | 6,125 |
| Total[(a)] | $ 766,276 |

(a) Excludes $19.3 million of net unamortized premium/discount, $33.4 million of net unamortized debt issuance costs, and $33.2 million of unamortized deferred gain on debt restructurings.

## 8. DERIVATIVE INSTRUMENTS AND FAIR VALUE MEASUREMENTS

Our results of operations and operating cash flows are impacted by changes in market prices for oil, natural gas and NGLs. To mitigate a portion of the exposure to adverse market changes, we enter into oil, natural gas and NGL commodity derivative instruments to establish price floor protection. As such, when commodity prices decline to levels that are less than our average price floor, we receive payments that supplement our cash flows. Conversely, when commodity prices increase to levels that are above our average price ceiling, we make payments to our counterparties. We do not enter into these arrangements for speculative trading purposes. As of September 30, 2017 and December 31, 2016, our commodity derivative instruments consisted of fixed rate swap contracts, puts, collars, swaptions, deferred put spreads, cap swaps, calls, basis swaps and three-way collars. We did not designate these instruments as cash flow hedges for accounting purposes. Accordingly, associated unrealized gains and losses are recorded directly as Gain (Loss) on Derivatives, Net.

We enter into the majority of our derivative arrangements with two counterparties and have a netting agreement in place with these counterparties. We do not obtain collateral to support the agreements, but we believe our credit risk is currently minimal on these transactions. For additional information on the credit risk regarding our counterparties, see Note 6, *Concentrations of Credit Risk,* to our Consolidated Financial Statements.

None of our commodity derivatives are designated for hedge accounting but are, to a degree, an economic offset to our commodity price exposure. We utilize the mark-to-market accounting method to account for these contracts. We recognize all gains and losses related to these contracts in the Consolidated Statements of Operations as Gain (Loss) on Derivatives, Net under Other Expense. We paid net cash settlements of $1.4 million and $6.9 million in relation to our commodity derivatives during the three and nine months ended September 30, 2017, respectively, and received net cash settlements of $2.1 million and $32.5 million in relation to our commodity derivatives during the three and nine months ended September 30, 2016, respectively.

As of September 30, 2017, we had 75.0% and 50.0% of our annualized condensate production hedged through the remainder of 2017 and 2018, respectively, over 90.0% and 65.0% of our annualized natural gas production hedged through the remainder of 2017 and 2018, respectively, and over 65.0% and 55.0% of our annualized NGL production hedged through the remainder of 2017 and 2018, respectively. These percentages exclude the effects of our basis swaps and do not include any estimated impact of increased production from future drilling and completion or the natural decline of our natural gas, condensate and NGL production.

*Contingent Consideration – Sale of Illinois Basin Operations*

In conjunction with the sale of our Illinois Basin operations, we executed a contract with the buyer that would allow us to receive future cash payments from the buyer if index pricing targets as defined in the contract are achieved at specified future dates. See Note 3, *Discontinued Operations / Assets Held for Sale*, to our Consolidated Financial Statements for additional information regarding the terms of the contract. We have evaluated the contract and concluded that it meets the definition and requirements for accounting treatment as a derivative instrument, as prescribed in ASC 815-10-15-83. We recorded the contract at its initial fair value of approximately $1.2 million as additional consideration in the calculation of the gain on the sale of the assets. Fair value was determined through application of mathematical models designed to provide fair value estimates utilizing probability measures and the market index measures underlying the contract. The fair value will be adjusted at each future reporting period for the duration of the contract, which concludes June 30, 2019. As of September 30, 2017 and December 31, 2016, the contingent consideration contract was valued at $1.0 million and $2.9 million, respectively.

*Derivative Instruments from Continuing Operations*

The following table summarizes the location and amounts of gains and losses on our derivative instruments from continuing operations, none of which are designated as hedges for accounting purposes, in our accompanying Consolidated Statements of Operations for the three and nine months ended September 30, 2017 and 2016:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| ($ in Thousands) | 2017 | 2016 | 2017 | 2016 |
| Oil | $ (691) | $ 1,214 | $ 1,244 | $ (955) |
| Natural Gas | $ (623) | 13,540 | $ 5,461 | 238 |
| NGLs | $ (16,675) | 2,126 | $ (4,034) | (7,589) |
| Refined Products | — | (14) | — | 52 |
| Contingent Consideration | $ (94) | — | $ (1,987) | — |
| Gain (Loss) on Derivatives, Net | $ (18,083) | $ 16,866 | $ 684 | $ (8,254) |

Our derivative instruments are recorded on the balance sheet as either an asset or a liability, in either case measured at fair value. The fair value associated with our derivative instruments was a net liability of approximately $20.6 million and approximately $28.2 million at September 30, 2017 and December 31, 2016, respectively.

Our open asset/(liability) financial commodity derivative instrument positions at September 30, 2017 consisted of:

| Period | Volume | | Put Option | Floor | Ceiling | Swap | Fair Market Value ($ in Thousands) |
|---|---|---|---|---|---|---|---|
| *Oil* | | | | | | | |
| 2017 - Swaps | 15,000 | Bbls | $ — | $ — | $ — | $ 54.00 | $ 30 |
| 2017 - Three-Way Collars | 39,000 | Bbls | 39.62 | 49.23 | 61.35 | — | 34 |
| 2018 - Swaps | 60,000 | Bbls | — | — | — | 54.00 | 120 |
| 2018 - Collars | 18,000 | Bbls | — | 53.00 | 60.00 | — | 56 |
| 2018 - Three-Way Collars | 66,000 | Bbls | 42.08 | 51.59 | 61.55 | — | 93 |
| 2019 - Swaps | 31,500 | Bbls | — | — | — | 51.00 | 4 |
| 2019 - Collars | 60,250 | Bbls | — | 45.00 | 55.07 | — | (11) |
| 2019 - Three-Way Collars | 24,000 | Bbls | 37.50 | 47.50 | 58.39 | — | 3 |
| 2020 - Swaps | 24,000 | Bbls | — | — | — | 51.00 | 4 |
| 2020 - Collars | 71,750 | Bbls | | 45.00 | 55.10 | — | (14) |
| 2020 - Three-Way Collars | 3,000 | Bbls | 37.50 | 47.50 | 59.00 | — | 2 |
| 2021 - Swaps | 6,000 | Bbls | — | — | — | 51.00 | 1 |
| 2021 - Collars | 63,750 | Bbls | — | 45.00 | 55.02 | — | (15) |
| 2022 - Collars | 36,000 | Bbls | — | 45.00 | 54.75 | — | (11) |
| | 518,250 | Bbls | | | | | $ 296 |
| *Natural Gas* | | | | | | | |
| 2017 - Swaps | 2,540,000 | Mcf | — | — | — | 3.12 | $ 306 |
| 2017 - Swaptions | 600,000 | Mcf | — | — | — | 3.33 | 161 |
| 2017 - Cap Swaps | 900,000 | Mcf | 2.35 | — | — | 2.81 | (314) |
| 2017 - Collars | 500,000 | Mcf | — | 2.88 | 3.43 | — | 34 |
| 2017 - Three-Way Collars | 4,550,000 | Mcf | 2.29 | 2.98 | 3.86 | — | 326 |
| 2017 - Calls | 750,000 | Mcf | — | — | 3.64 | — | (59) |
| 2017 - Basis Swaps - Dominion South | 3,355,000 | Mcf | — | — | — | (0.81) | (343) |
| 2017 - Basis Swaps - Texas Gas | 3,680,000 | Mcf | — | — | — | (0.13) | 38 |
| 2018 - Swaps | 15,335,000 | Mcf | — | — | — | 3.10 | 779 |
| 2018 - Swaptions | — | Mcf | — | — | — | — | (117) |
| 2018 - Three-Way Collars | 10,600,000 | Mcf | 2.33 | 2.90 | 3.52 | — | 155 |
| 2018 - Calls | 5,810,000 | Mcf | — | — | 3.97 | — | (384) |
| 2018 - Collars | 450,000 | Mcf | — | 3.20 | 3.65 | — | 52 |
| 2018 - Basis Swaps - Dominion South | 12,775,000 | Mcf | — | — | — | (0.83) | (2,916) |
| 2018 - Basis Swaps - Texas Gas | 14,600,000 | Mcf | — | — | — | (0.13) | 150 |
| 2019 - Swaps | 10,470,000 | Mcf | — | — | — | 2.84 | (281) |
| 2019 - Three-Way Collars | 8,205,000 | Mcf | 2.27 | 2.77 | 3.40 | — | 10 |
| 2019 - Collars | 4,580,000 | Mcf | — | 2.50 | 3.05 | — | (124) |
| 2019 - Basis Swaps - Dominion South | 12,775,000 | Mcf | — | — | — | (0.84) | (3,217) |
| 2020 - Swaps | 4,560,000 | Mcf | — | — | — | 2.87 | (292) |
| 2020 - Three-Way Collars | 4,555,000 | Mcf | 2.23 | 2.73 | 3.30 | — | (8) |
| 2020 - Collars | 4,115,000 | Mcf | — | 2.50 | 3.05 | — | (165) |
| 2020 - Basis Swaps - Dominion South | 7,320,000 | Mcf | — | — | — | (0.84) | (1,900) |
| 2021 - Swaps | 3,875,000 | Mcf | — | — | — | 2.77 | (162) |
| 2021 - Three-Way Collars | 3,037,500 | Mcf | 2.17 | 2.67 | 3.15 | — | (56) |
| 2021 - Collars | 2,737,500 | Mcf | — | 2.50 | 3.05 | — | (165) |
| 2021 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| 2022 - Swaps | 2,730,000 | Mcf | — | — | — | 2.73 | (89) |
| 2022 - Three-Way Collars | 2,047,500 | Mcf | 2.15 | 2.65 | 3.10 | — | (54) |
| 2022 - Collars | 2,047,500 | Mcf | — | 2.50 | 3.05 | — | (124) |
| 2022 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| 2023 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| 2024 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| | 164,100,000 | Mcf | | | | | $ (11,563) |
| *NGLs* | | | | | | | |
| 2017 - C3+ NGL Swaps | 409,000 | Bbls | — | — | — | 29.22 | $ (4,847) |
| 2017 - Ethane Swaps | 225,000 | Bbls | — | — | — | 10.58 | (214) |
| 2018 - C3+ NGL Swaps | 1,125,072 | Bbls | — | — | — | 31.93 | (4,156) |
| 2018 - Ethane Swaps | 1,150,000 | Bbls | — | — | — | 12.95 | 494 |
| 2019 - C3+ NGL Swaps | 392,814 | Bbls | — | — | — | 28.61 | (1,097) |
| 2019 - C5 Collars | 113,040 | Bbls | — | 45.00 | 54.83 | — | (38) |
| 2019 - Ethane Swaps | 595,000 | Bbls | — | — | — | 13.06 | 159 |
| 2020 - C3+ NGL Swaps | 261,228 | Bbls | — | — | — | 37.11 | (395) |
| 2020 - C5 Collars | 28,260 | Bbls | — | 45.00 | 54.83 | — | (10) |
| 2020 - Ethane Swaps | 356,000 | Bbls | — | — | — | 12.89 | (35) |
| 2021 - C3+ NGL Swap | 133,620 | Bbls | — | — | — | 44.72 | (85) |
| 2021 - Ethane Swaps | 175,000 | Bbls | — | — | — | 12.84 | (29) |
| 2022 - C3+ NGL Swap | 39,564 | Bbls | — | — | — | 50.57 | (3) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2022 - Ethane Swaps | 47,000 | Bbls | — | — | — | 12.81 | (20) |
| | 5,050,598 | Bbls | | | | | $ (10,276) |

The combined fair value of derivatives, none of which are designated or qualifying as hedges, included in our Consolidated Balance Sheets as of September 30, 2017 and December 31, 2016 is summarized below:

| ($ in Thousands) | September 30, 2017 | December 31, 2016 |
|---|---|---|
| **Short-Term Derivative Assets:** | | |
| Crude Oil—Three-Way Collars | $ 109 | $ — |
| Crude Oil—Swaps | 120 | — |
| Crude Oil—Collars | 56 | — |
| NGL—Swaps | 394 | — |
| Natural Gas—Swaps | 1,228 | 206 |
| Natural Gas—Cap Swaps | — | 61 |
| Natural Gas—Collars | 86 | — |
| Natural Gas—Basis Swaps | 445 | 232 |
| Natural Gas—Three-Way Collars | 844 | 151 |
| Natural Gas—Swaption | 161 | — |
| Contingent Consideration - Sale of Illinois Basin | 461 | 1,223 |
| Total Short-Term Derivative Assets | $ 3,904 | $ 1,873 |
| **Long-Term Derivative Assets:** | | |
| Crude Oil—Three-Way Collars | $ 33 | $ — |
| Crude Oil—Swaps | 40 | — |
| Crude Oil—Collars | 2 | — |
| NGL—Swaps | 342 | — |
| Natural Gas—Swaps | 235 | 206 |
| Natural Gas—Basis Swaps | 45 | 293 |
| Natural Gas—Three-Way Collars | 280 | — |
| Contingent Consideration - Sale of Illinois Basin | 488 | 1,713 |
| Total Long-Term Derivative Assets | $ 1,465 | $ 2,212 |
| **Total Derivative Assets** | $ 5,369 | $ 4,085 |
| **Short-Term Derivative Liabilities:** | | |
| Crude Oil—Collars | $ — | $ (86) |
| Crude Oil—Deferred Put Spread | — | (9) |
| Crude Oil—Three-Way Collars | (2) | (132) |
| Crude Oil—Swaps | — | (220) |
| NGL—Swaps | (8,262) | (9,895) |
| Natural Gas—Three-Way Collars | (397) | (2,397) |
| Natural Gas—Cap Swaps | (314) | (3,364) |
| Natural Gas—Collars | — | (873) |
| Natural Gas—Basis Swaps | (2,750) | (640) |
| Natural Gas—Call | (347) | (1,478) |
| Natural Gas—Swaption | (88) | (1,258) |
| Natural Gas—Swaps | (317) | (4,673) |
| Total Short - Term Derivative Liabilities | $ (12,477) | $ (25,025) |
| **Long-Term Derivative Liabilities:** | | |
| Crude Oil—Three-Way Collars | $ (9) | $ (58) |
| Crude Oil—Swaps | — | (146) |
| Crude Oil—Collars | (53) | — |
| NGL—Swaps | (2,702) | (2,200) |
| NGL—Collars | (48) | — |
| Natural Gas—Swaps | (884) | (1,004) |
| Natural Gas—Swaption | (29) | (167) |
| Natural Gas—Basis Swaps | (8,734) | (1,260) |
| Natural Gas—Collars | (577) | (115) |
| Natural Gas—Call | (96) | (491) |
| Natural Gas—Three-Way Collars | (354) | (1,786) |
| Total Long-Term Derivative Liabilities | $ (13,486) | $ (7,227) |
| **Total Derivative Liabilities** | $ (25,963) | $ (32,252) |

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 (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to utilize the best available information. We utilize a fair value hierarchy that gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

Level 1—Observable inputs, such as quoted prices in active markets for identical assets or liabilities as of the reporting date.

Level 2—Observable inputs other than quoted prices within Level 1 for similar assets and liabilities. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars and other like derivative contracts, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Level 3—Unobservable inputs that are supported by little or no market activity. Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Our Level 2 fair value measurements are comprised of our derivative contracts and are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors, interest rates and discount rates, or can be confirmed from other active markets. The fair values recorded as of September 30, 2017 and December 31, 2016 were based upon quotes obtained from the counterparties to these contracts and verified by an independent third party.

We had no Level 3 commodity derivative contracts outstanding as of September 30, 2017 or December 31, 2016.

The fair value of our derivative instruments may be different from the settlement value based on company-specific inputs, such as credit ratings, futures markets and forward curves, and readily available buyers and sellers for such assets and liabilities. During the three and nine months ended September 30, 2017 and for the year ended December 31, 2016 there were no transfers into or out of Level 1 or Level 2 measurements. The following table presents the fair value hierarchy table for assets and liabilities measured at fair value:

| | | Fair Value Measurements at September 30, 2017 | | |
|---|---|---|---|---|
| ($ in Thousands) | Total Carrying Value as of September 30, 2017 | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |
| Commodity Derivatives | $ (20,594) | $ — | $ (20,594) | $ — |

| | | Fair Value Measurements at December 31, 2016 | | |
|---|---|---|---|---|
| ($ in Thousands) | Total Carrying Value as of December 31, 2016 | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |
| Commodity Derivatives | $ (28,167) | $ — | $ (28,167) | $ — |

Net derivative asset values are determined primarily by quoted futures and options prices and utilization of the counterparties' credit default risk and net derivative liabilities are determined primarily by quoted futures and options prices and utilization of our credit default risk. The credit default risk of our counterparties and us are based on metrics such as interest coverage, operating cash flow and leverage ratios that calculate the likelihood that a firm will be unable to repay its lenders or fulfill payment obligations.

The value of our oil derivatives are comprised of three-way collar, call protected swap and deferred put spread contracts for notional barrels of oil at interval New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") oil prices. The fair values attributable to our oil derivatives as of September 30, 2017 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for WTI oil and (iii) the implied rate of volatility inherent in the contracts. The implied rates of volatility inherent in our contracts were determined based on market-quoted volatility factors. Our gas derivatives are comprised of swap, collars, swaption, three way collar, basis swap, cap swap, call and put spread contracts for notional volumes of gas contracted at NYMEX Henry Hub ("HH"). The fair values attributable to our gas derivative contracts as of September 30, 2017 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for HH gas, (iii) independent market-quoted forward index prices and (iv) the implied rate of volatility inherent in the contracts. The implied rates of volatility inherent in our contracts were determined based on market-quoted volatility factors. Our NGL derivatives are comprised of swaps for notional volumes of NGLs contracted at NYMEX Mont Belvieu. The fair values attributable to our NGL derivative contracts as of September 30, 2017 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for Mont Belvieu, (iii) independent market-quoted forward index prices and (iv) the implied rate of volatility inherent in the contracts. The implied rates of volatility inherent in our contracts were determined based on market-quoted volatility factors. We classify our derivatives as Level 2 if the inputs used in the valuation models are directly observable for substantially the full term of the instrument; however, if the significant inputs were not observable for substantially the full term of the instrument, we would classify those derivatives as Level 3. We categorize our measurements as Level 2 because the valuation of our derivative instruments are based on similar transactions observable in active markets or industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instruments.

*Future Abandonment Cost*

We report the fair value of asset retirement obligations on a nonrecurring basis in our Consolidated Balance Sheets. We estimate the fair value of asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. These inputs are unobservable, and thus result in a Level 3 classification. See Note 2, *Future Abandonment Costs,* to our Consolidated Financial Statements for further information on asset retirement obligations, which includes a reconciliation of the beginning and ending balances.

*Financial Instruments Not Recorded at Fair Value*

The following table sets forth the fair values of financial instruments that are not recorded at fair value in our Consolidated Financial Statements:

| | September 30, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| ($ in Thousands) | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Senior Notes, Net | $ 654,713 | $ 265,015 | $ 638,161 | $ 147,605 |
| Secured Line of Credit, Net of Issuance Costs | — | — | 113,785 | 113,785 |
| Term Loans, Net | 148,351 | 148,351 | — | — |
| Capital Leases and Other Obligations | 10,474 | 7,278 | 4,173 | 3,234 |
| Total | $ 813,538 | $ 420,644 | $ 756,119 | $ 264,624 |

The fair value of the secured lines of credit approximates carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and would be classified as Level 2 in the fair value hierarchy.

The fair value of the Senior Notes uses pricing that is readily available in the public market. Accordingly, the fair value of the Senior Notes would be classified as Level 1 in the fair value hierarchy. The fair value of our capital leases and other obligations are determined using a discounted cash flow approach based on the interest rate and payment terms of the obligations and assumed discount rate. The fair values of the obligations could be significantly influenced by the discount rate assumptions, which is unobservable. Accordingly, the fair value of the capital leases and other obligations would be classified as Level 3 in the fair value hierarchy.

The carrying values of all classes of cash and cash equivalents, accounts receivables and accounts payables are considered to be representative of their respective fair values due to the short term maturities of those instruments.

*Other Fair Value Measurements*

During the nine months ended September 30, 2017 and 2016, we recorded other than temporary impairments of $16.5 million and $45.3 million, respectively, related to proven and unproved properties. We primarily use proved reserve reports in our determination of impairment. These proved reserve reports are generated with inputs that are primarily established internally with the use of internally developed engineering estimates and methodologies. The inputs used in determining fair value as a part of the impairment expense calculation are considered to be Level 3 within the fair value hierarchy. For additional information on our impairment expense, see Note 15, *Impairment Expense*, to our Consolidated Financial Statements.

**9. INCOME TAXES**

We recognize deferred income taxes for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and net operating loss and credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of any tax rate change on deferred taxes is recognized in the period that includes the enactment date of the tax rate change. Realization of deferred tax assets is assessed and, if not more likely than not, a valuation allowance is recorded to write down the deferred tax assets to their net realizable value.

Income tax included in continuing operations was as follows:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| ($ in Thousands) | 2017 | 2016 | 2017 | 2016 |
| Income Tax Benefit (Expense) | $ — | $ 8,106 | $ — | $ 5,785 |
| Effective Tax Rate | 0.0% | 33.0% | 0.0% | 4.5% |

Management estimates the annual effective income tax rate quarterly, based on current annual forecasted results. Items unrelated to current year ordinary income are recognized entirely in the period identified as a discrete item of tax. The quarterly income tax provision is comprised of tax on ordinary income provided at the most recent estimated annual effective tax rate, adjusted for the tax effect of these discrete items. We account for the tax effects of discontinued operations as a discrete item and therefore recognizes the full tax effects of discontinued operations in the same period that the pretax income or loss from discontinued operations is recognized. This approach results in a tax benefit being recorded in continuing operations to offset the tax charge on the gain recorded in discontinued operations, when a full valuation allowance exists on the deferred tax attributes of the Company's entire operations.

For the nine months ended September 30, 2017, the estimated annual effective tax rate applied to ordinary losses from continuing operations was 0.0%. The estimated annual effective tax rate differs from the U.S. statutory rate of 35.0% primarily due to the effect of maintaining a full valuation allowance against our deferred tax assets. Discrete period tax expense was not material and is also offset by a full valuation allowance resulting in zero tax expense for the period.

For the nine months ended September 30, 2016, the estimated annual effective tax rate applied to ordinary losses from continuing operations was 4.5%. The estimated annual effective tax rate differs from the U.S. statutory rate of 35.0% primarily due to the effect of having full valuation allowances recorded against our deferred tax assets coupled with recognizing tax benefits in continuing operations for the effect of taxable income generated by our discontinued operations. To a lesser extent, the annual effective rate is also influenced by alternative minimum tax with no corresponding deferred tax benefit due to the full valuation allowance, and state taxes in certain tax paying jurisdictions. Our alternative minimum tax due for 2016 is driven primarily by cancellation of debt income of $543.2 million related to the Senior Note exchanges discussed in Note 7, *Long-Term Debt*, to our Consolidated Financial Statements. We recorded a benefit for income taxes from continuing operations of $5.8 million for the nine months ended September 30, 2016

Income tax payments made during the nine months ended September 30, 2017 were $2.0 million, and payments made during the nine months ended September 30, 2016 were negligible. Tax refunds received during the nine months ended September 30, 2017 were approximately $0.2 million, and refunds received during the nine months ended September 30, 2016 were negligible.

## 10. CAPITAL STOCK

*Reverse Stock Split*

As discussed in Note 1, *Basis of Presentation and Principles of Consolidation*, references to numbers of shares of common stock and per share data in the accompanying financial statements and notes thereto have been adjusted to reflect the reverse stock split on a retroactive basis.

*Common Stock*

On May 27, 2016, our common shareholders approved an increase in the number of authorized shares from 100,000,000 to 200,000,000 common shares. On May 5, 2017, our common shareholders approved a decrease in the number of authorized shares from 200,000,000 to 100,000,000 common shares, contingent upon the effectiveness of a reverse stock split, which occurred on May 12, 2017. As of September 30, 2017, we have authorized capital stock of 100,000,000 shares of common stock and 100,000 shares of preferred stock. As of September 30, 2017 and December 31, 2016, shares of common stock issued and outstanding totaled 9,935,383 and 9,787,146, respectively. During the nine months ended September 30, 2017, we issued approximately 0.1 million shares of our common stock in conjunction with debt for equity exchanges completed with certain holders of our Senior Notes. See Note 7, *Long-Term Debt*, to our Consolidated Financial Statements for additional information regarding our debt and equity exchanges.

*Preferred Stock*

As of both September 30, 2017 and December 31, 2016, 3,987 shares of our 6.0% Convertible Perpetual Preferred Stock, Series A, par value $0.001 per share ("Series A Preferred Stock"), were issued and outstanding. During the nine months ended

September 30, 2016, 12,013 shares of Series A Preferred Stock were converted into approximately 0.9 million shares of common stock pursuant to the terms of the Series A Preferred Stock, and through negotiated exchanges with certain holders of the Series A Preferred Shares. See Note 13, *Earnings Per Common Share*, to our Consolidated Financial Statements, for additional information regarding the effect of the preferred stock conversions on Net Income (Loss) Attributable to Common Shareholders.

The annual dividend on each share of the Series A Preferred Stock is 6.0% per annum on the liquidation preference of $10,000 per share and is payable quarterly, in arrears, on February 15, May 15, August 15 and November 15 of each year.

We pay cumulative dividends, when and if declared, in cash, stock or a combination thereof, on a quarterly basis at a rate of $600 per share, or 6.0%, per year. Dividends that are not declared and paid in accordance with the quarterly schedule will accumulate from the most recent date upon which dividends were paid but will not bear interest. In February 2016, we suspended our quarterly dividend payment. During the three and nine months ended September 30, 2017, we paid cash dividends of $150.00 per share in the aggregate amount of $0.6 million and $1.2 million, respectively, for the periods of November 15, 2015 to February 15, 2016 and February 15, 2016 to May 15, 2016. As of September 30, 2017, accumulated dividends in arrears totaled $3.0 million. While the accumulation does not result in the presentation of a liability on the Consolidated Balance Sheets, the accumulation of unpaid dividends during the current reporting period is included in our Net Income (Loss) in the determination of Net Income (Loss) Attributable to Common Shareholders and related earnings per share calculations.

If dividends are in arrears and unpaid for six or more quarterly periods (whether or not consecutive), the holders of the shares of Series A Preferred Stock will have the right to elect two additional directors to serve on our board of directors.

## 11. EMPLOYEE BENEFIT AND EQUITY PLANS

*Equity Plans*

We recognize all share-based payments to employees, including grants of employee stock options, in our Consolidated Statements of Operations based on their grant-date fair values, using prescribed option-pricing models where applicable. The fair value is expensed over the requisite service period of the individual grantees, which generally equals one vesting period. We report any benefits of income tax deductions in excess of recognized financial accounting compensation as cash flows from financing activities, rather than as cash flows from operating activities.

*Stock Options*

During the nine months ended September 30, 2017, no new options to purchase shares of our common stock were granted. During the nine months ended September 30, 2016, we issued 88,892 options to purchase shares of our common stock to 34 employees. Stock-based compensation expense from continuing operations relating to stock options outstanding for the three and nine months ended September 30, 2017 was $0.1 million and $0.3 million, respectively. Stock-based compensation expense from continuing operations relating to stock options outstanding for each of the three and nine months ended September 30, 2016 was $0.1 million and $0.2 million, respectively. The expense related to stock option grants was recorded on our Consolidated Statements of Operations under the heading of General and Administrative Expense. There were no stock options exercised during the nine months ended September 30, 2017. There was no tax benefit related to stock option exercises for each of the nine-month periods ended September 30, 2017 and 2016.

A summary of the status of our issued and outstanding stock options as of September 30, 2017 is as follows:

| | Outstanding | | Exercisable | |
|---|---|---|---|---|
| Exercise Price | Number Outstanding at September 30, 2017 | Weighted-Average Exercise Price | Number Exercisable at September 30, 2017 | Weighted-Average Exercise Price |
| 9.70 | 2,750 | $ 9.70 | 918 | $ 9.70 |
| 16.90 | 70,853 | $ 16.90 | 25,125 | $ 16.90 |
| 40.50 | 4,000 | $ 40.50 | — | $ 40.50 |
| 49.00 | 4,000 | $ 49.00 | 666 | $ 49.00 |
| 50.40 | 3,070 | $ 50.40 | 3,070 | $ 50.40 |
| 95.00 | 5,000 | $ 95.00 | 5,000 | $ 95.00 |
| 99.90 | 6,959 | $ 99.90 | 6,959 | $ 99.90 |
| 104.20 | 2,217 | $ 104.20 | 2,217 | $ 104.20 |
| 223.40 | 3,000 | $ 223.40 | 3,000 | $ 223.40 |
| | 101,849 | $ 37.39 | 46,955 | $ 57.34 |

The weighted average remaining contractual term for options outstanding at September 30, 2017 was 4.5 years and there was no aggregate intrinsic value. The weighted average remaining contractual term for options exercisable at September 30, 2017 was 3.4

years and there was no aggregate intrinsic value. As of September 30, 2017, unrecognized compensation expense related to stock options was $0.1 million.

*Restricted Stock Awards*

During the nine-month period ended September 30, 2017, the Compensation Committee approved the issuance of an aggregate of 101,237 shares of restricted common stock to 28 employees. During the nine-month period ended September 30, 2016, the Compensation Committee approved the issuance of an aggregate of 567,205 shares of restricted stock to 51 employees. Certain of our outstanding restricted stock awards granted in 2015 are subject to market-based vesting through a calculation of total shareholder return ("TSR") of our common stock relative to a pre-defined peer group over a three-year period.

The weighted average fair value of the TSR awards granted as of December 31, 2015 was $2.56 per share. There have been no TSR awards granted subsequent to December 31, 2015. Average fair values were estimated on the date of each grant using a Monte Carlo Simulation model that estimates the most likely outcome based on the terms of the award and used the following assumptions:

| | Nine Months Ended September 30, 2017 | Year Ended December 31, 2016 |
|---|---|---|
| Expected Dividend Yield | 0.0% | 0.0% |
| Risk-Free Interest Rate | 1.0% | 1.0% |
| Expected Volatility – Rex Energy | 58.6% | 58.6% |
| Expected Volatility – Peer Group | 29.8%-85.0% | 29.8%-85.0% |
| Market Index | 35.6% | 35.6% |
| Expected Life | Three Years | Three Years |

During the nine months ended September 30, 2017, 17,952 performance stock awards were forfeited due to not meeting specified targets, which resulted in a net reversal of prior compensation expense of approximately $0.1 million for the quarter. Compensation expense from restricted stock awards associated with our continuing operations was $0.3 million and $0.7 million for the three and nine months ended September 30, 2017, respectively, and $0.9 million and $1.8 million for the three and nine months ended September 30, 2016, respectively. During the first quarter of 2016, 23,557 performance stock awards were forfeited due to not meeting specified targets, which resulted in a net reversal of prior compensation expense of approximately $0.2 million for the quarter. As of September 30, 2017, total unrecognized compensation cost related to restricted common stock grants was approximately $0.8 million, which will be recognized over a weighted average period of 1.6 years.

A summary of the restricted stock activity for the nine months ended September 30, 2017 is as follows:

| | Number of Shares | Weighted-Average Grant Date Fair Value |
|---|---|---|
| Restricted stock awards, as of December 31, 2016 | 242,824 | $ 26.34 |
| Awards | 101,237 | 5.18 |
| Forfeitures | (36,663) | 52.96 |
| Vested | (102,308) | 21.52 |
| Restricted stock awards, as of September 30, 2017 | $ 205,090 | $ 13.54 |

## 12. COMMITMENTS AND CONTINGENCIES

*Legal Reserves*

We are involved in various legal proceedings that arise in the ordinary course of our business. Although we cannot predict the outcome of these proceedings with certainty, we do not currently expect these matters to have a material adverse effect on our consolidated financial position or results of operations.

The accrual of reserves for legal matters is included in Accrued Liabilities on our Consolidated Balance Sheets. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and the subjective judgment of management. While we believe that these reserves are adequate, there are uncertainties associated with legal proceedings and we can give no assurance that our estimate of any related liability will not increase or decrease in the future. The reserved and unreserved exposures for our legal proceedings could change based upon developments in those proceedings or changes in the facts and circumstances. It is possible that we could incur losses in excess of the amounts currently accrued. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures for legal proceedings will exceed our current accruals by an amount that would have a material adverse effect on our consolidated financial position, although cash flow could be significantly impacted in the reporting periods in which such costs are incurred.

For the quarter ended September 30, 2017, there were no significant changes with respect to the legal matters disclosed in our Annual Report on Form 10-K for the year ended December 31, 2016, as supplemented by our Periodic Report on Form 10-Q for the period ended September 30, 2017.

*Environmental*

Due to the nature of the oil and natural gas business, we are exposed to possible environmental risks. We have implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. We conduct periodic reviews of our policies and properties to identify changes in the environmental risk profile. In these reviews we evaluate whether there is a probable liability, its amount and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any remediation effort.

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. As of September 30, 2017, we know of no significant probable or possible environmental contingent liabilities.

*Letters of Credit*

As of September 30, 2017, we have posted $32.2 million in various letters of credit to secure our drilling and related operations.

*Lease Commitments*

As of September 30, 2017, we have lease commitments for various real estate leases. Rent expense is recognized on a straight-line basis and has been recorded in General and Administrative expense on our Consolidated Statements of Operations. Rent expense for the three and nine months ended September 30, 2017 was approximately $0.3 million and $0.7 million, respectively, and $0.3 million and $0.9 million for the three and nine months ended September 30, 2016, respectively. Lease commitments by year for each of the next five years are presented in the table below:

| ($ in Thousands) | | |
|---|---|---|
| 2017 | $ | 252 |
| 2018 | | 1,013 |
| 2019 | | 1,020 |
| 2020 | | 888 |
| 2021 | | 475 |
| Thereafter | | 485 |
| Total | $ | 4,133 |

*Capacity Reservation*

We have a capacity reservation arrangement with a subsidiary of MarkWest Energy Partners, L.P. (“MarkWest”) to ensure sufficient capacity at the cryogenic gas processing plants owned by MarkWest in Butler County, Pennsylvania to process our produced natural gas. In the event that we do not utilize the plants to process quantities of gas sufficient to meet specified volume commitments, we may be obligated to pay approximately $4.4 million in 2017, $15.9 million in 2018, $15.8 million in 2019, $15.9 million in 2020, $15.9 million in 2021 and $78.0 million thereafter, assuming our average net revenue interest in the region of approximately 51%. Charges incurred for unutilized processing capacity with MarkWest during the three and nine months ended September 30, 2017 were $1.3 million and $4.6 million, respectively, and $0.8 million and $2.2 million for the three and nine months ended September 30, 2016, respectively

*Water Supply Commitments*

We have contracted with a water district in Ohio to supply bulk water in support of our Ohio drilling operations. The contract is effective from July 5, 2017 through July 4, 2022. Over the duration the contract, we are obligated to purchase 150 million gallons of water at a fixed price of $7.50 per 1,000 gallons.  As of September 30, 2017, our future commitment for unpurchased volumes is approximately $1.0 million.

*Operational Commitments*

We have contracted drilling rig services for one rig to support our Appalachian Basin operations. The minimum cost to retain the rig would require gross payments of approximately $0.7 million in 2017 and $1.8 million in 2018, which would be partially offset by other working interest owners, which vary from well to well.

*Natural Gas Gathering, Processing and Sales Agreements*

During the normal course of business, we have entered into certain agreements to ensure the gathering, transportation, processing and sales of specified quantities of our natural gas, NGLs and condensate. In some instances, we are obligated to pay shortfall fees, whereby we would pay a fee for any difference between actual volumes provided as compared to volumes that have been committed. In other instances, we are obligated to pay a fee on all volumes that are subject to the related agreement. In connection with our entry into certain of these agreements, we concurrently entered into a guaranty whereby we have guaranteed the payment of obligations under the specified agreements up to a maximum of $384.4 million through 2029.

For the three and nine months ended September 30, 2017, we incurred expenses related to the transportation, processing and marketing of our natural gas, condensate and NGLs of approximately $27.8 million and $80.5 million, respectively, and $22.9 million and $66.2 million for the three and nine months ended September 30, 2016, respectively. Expense related to these agreements makes up a substantial portion of our Lease Operating Expense, which we expect to continue as existing agreements commence and new transportation, processing and marketing agreements are entered that will enable us to sell our product. During the three and nine months ended September 30, 2017, we incurred fees related to unutilized capacity commitments of approximately $0.7 million and $2.1 million, respectively, and $0.7 million and $1.7 million for the three and nine months ended September 30, 2016, respectively. The unutilized commitment fees are related to undeveloped properties that we acquired during 2014. Minimum net obligations under these sales, gathering and transportation agreements for the next five years are as follows:

| ($ in Thousands) | | |
|---|---|---|
| 2017 | $ | 11,709 |
| 2018 | | 47,222 |
| 2019 | | 47,706 |
| 2020 | | 46,390 |
| 2021 | | 43,344 |
| Thereafter | | 482,315 |
| Total | $ | 678,686 |

*Pennsylvania Impact Fee*

In 2012, Pennsylvania instituted a natural gas impact fee on producers of unconventional natural gas. The fee is imposed on every producer of unconventional gas and applies to unconventional wells spud in Pennsylvania regardless of when spudding occurred. The fee for each unconventional gas well is determined using the following matrix, with vertical unconventional gas wells being charged 20% of the applicable rates:

| | **<$2.25(a)** | | **$2.26 - $2.99(a)** | | **$3.00 - $4.99(a)** | | **$5.00 - $5.99(a)** | | **>$5.99(a)** | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year One | $ | 40,200 | $ | 45,300 | $ | 50,300 | $ | 55,300 | $ | 60,400 |
| Year Two | $ | 30,200 | $ | 35,200 | $ | 40,200 | $ | 45,300 | $ | 55,300 |
| Year Three | $ | 25,200 | $ | 30,200 | $ | 30,200 | $ | 40,200 | $ | 50,300 |
| Year 4 – 10 | $ | 10,100 | $ | 15,100 | $ | 20,100 | $ | 20,100 | $ | 20,100 |
| Year 11 – 15 | $ | 5,000 | $ | 5,000 | $ | 10,100 | $ | 10,100 | $ | 10,100 |

(a) Pricing utilized for determining annual fee is based on the arithmetic mean of the NYMEX settled price for the near-month contract as reported by the Wall Street Journal for the last trading day of each month of a calendar year for the 12-month period ending December 31.

All fees owed are due on April 1 of each year. For the three and nine months ended September 30, 2017, we recorded expense of approximately $0.9 million and $2.5 million, respectively, and $0.8 million and $2.1 million for the three and nine months ended September 30, 2016, respectively. We record expenses related to the impact fees as Production and Lease Operating Expense. As of September 30, 2017, approximately $2.4 million was accrued for the 2017 impact fees.

## 13. EARNINGS PER COMMON SHARE

Basic income (loss) per common share is calculated based on the weighted average number of common shares outstanding at the end of the period, excluding restricted stock with performance-based and market-based vesting criteria. Diluted income per common share includes the speculative exercise of stock options and performance-based restricted stock which contain conditions that are not earnings or market-based, given that the hypothetical effect is not anti-dilutive. For the three and nine months ended September 30, 2017, we excluded stock options to purchase 101,849 shares of our common stock, due to the exercise price of all exercisable outstanding options exceeding the average market price of our common shares during the period. For the three and nine months ended September 30, 2016, we excluded stock options to purchase 130,447 shares of our common stock, due to our Net Loss from Continuing Operations. For the three and nine month periods ended September 30, 2017 and 2016, we excluded performance-based restricted stock of 38,704 shares and 67,290 shares, respectively, due to performance metrics that have not yet been attained (for additional information on our non-cash compensation plans, see Note 11, *Employee Benefit and Equity Plans*, to our Consolidated Financial Statements). We utilize the if-converted method for calculating the impact of our 6.0% Convertible Perpetual Preferred Stock on diluted earnings per share. Under the if-converted method, convertible preferred stock is assumed as converted to common shares for the weighted average period outstanding. For the three and nine months ended September 30, 2017, we excluded the assumed conversion of preferred stock equating to 221,502 common shares due to the antidilutive effect caused by the assumed conversion. During the three and nine months ended September 30, 2016, we excluded the assumed conversion of preferred stock equating to 713,117 common shares and 227,057 common shares, respectively, due to our Net Loss from Continuing Operations. The following table sets forth the computation of basic and diluted earnings per common share:

| (in thousands, except per share amounts) | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| Numerator: | 2017 | 2016 | 2017 | 2016 |
| Net Loss From Continuing Operations | $ (46,534) | $ (16,477) | $ (53,454) | $ (122,040) |
| Net Income From Discontinued Operations | — | 21,892 | — | 12,719 |
| Less: Preferred Stock Dividends | (598) | (613) | (1,794) | (4,441) |
| Effect of Preferred Stock Conversions | — | — | — | 72,316 |
| Net Income (Loss) Attributable to Common Shareholders | $ (47,132) | $ 4,802 | $ (55,248) | $ (41,446) |
| Denominator: | | | | |
| Weighted Average Common Shares Outstanding - Basic | 9,906 | 9,080 | 9,859 | 7,310 |
| Effect of Dilutive Securities: | | | | |
| Employee Stock Options | — | — | — | — |
| Employee Performance-Based Restricted Stock Awards | — | — | — | — |
| Effect of Assumed Conversions of Preferred Stock | — | — | — | — |
| Weighted Average Common Shares Outstanding - Diluted | 9,906 | 9,080 | 9,859 | 7,310 |
| Earnings per Common Share Attributable to Rex Energy Common Shareholders: | | | | |
| Basic — Net Loss From Continuing Operations | $ (4.76) | $ (1.89) | $ (5.60) | $ (7.41) |
| — Net Income From Discontinued Operations | — | 2.41 | — | 1.74 |
| — Net Income (Loss) Attributable to Common Shareholders | $ (4.76) | $ 0.52 | $ (5.60) | $ (5.67) |
| Diluted — Net Loss From Discontinued Operations | $ (4.76) | $ (1.89) | $ (5.60) | $ (7.41) |
| — Net Income From Discontinued Operations | — | 2.41 | — | 1.74 |
| — Net Income (Loss) Attributable to Common Shareholders | $ (4.76) | $ 0.52 | $ (5.60) | $ (5.67) |

## 14. EQUITY METHOD INVESTMENTS

*RW Gathering, LLC*

We own a 40% non-operated interest in RW Gathering, LLC ("RW Gathering"), which owns gas-gathering assets to facilitate development in our natural gas operations. We did not make any capital contributions to RW Gathering during the first nine months of 2017 and 2016. RW Gathering recorded net losses from continuing operations of $0.5 million and $1.5 million during the three and nine months ended September 30, 2017, respectively, as compared to losses of $0.5 million and $1.5 million for the three and nine months ended September 30, 2016, respectively. The losses incurred were due to insurance fees, bank fees, rent expenses and depreciation expense. Historically, we recorded our share of the net losses on the Statements of Operations as Loss on Equity Method Investments. As of June 30, 2015, we discontinued applying the equity method of accounting for our share of net losses due to our investment being reduced to zero.

During the three and nine months ended September 30, 2017, we incurred approximately $0.1 million and $0.4 million, respectively, as compared to $0.2 million and $0.5 million for the three and nine months ended September 30, 2016, respectively, in compression expenses each year that were charged to us from Williams Production Appalachia, LLC. These costs are in relation to compression costs incurred by RW Gathering and are recorded as Production and Lease Operating Expense on our Consolidated Statement of Operations. As of September 30, 2017 and December 31, 2016, there were no receivables or payables due between RW Gathering and us.

## 15. IMPAIRMENT EXPENSE

For the three and nine months ended September 30, 2017, impairment expenses incurred were approximately $11.9 million and $16.5 million, respectively, and impairment expenses incurred for the three and nine months ended September 30, 2016 were approximately $9.6 million and $45.3 million, respectively. We continually monitor the carrying value of our oil and gas properties and make evaluations of their recoverability when circumstances arise that may contribute to impairment. The expense incurred during the first nine months of 2017 included approximately $7.0 million of undeveloped leases that expired or are expected to expire without being developed, the majority of which are in Butler County, Pennsylvania, and Warrior North in Ohio. Impairments of proved properties in our Butler County operations totaled approximately $9.4 million during the first nine months of 2017. The impairments were identified through an analysis of market conditions and future development plans that were in existence as of each period end related to these properties, which indicated that the carrying value of the assets was not recoverable. The analysis included an evaluation of estimated future cash flows with consideration given to market prices for similar assets and future development plans. Our estimates of future cash flows attributable to our oil and gas properties could decline if commodity prices decline, which may result in our incurrence of additional impairment expense. As of September 30, 2017, we continued to carry the costs of undeveloped properties of approximately $201.3 million on our Consolidated Balance Sheet, which is primarily related to the Marcellus and Utica Shale and for which we currently have development, trade or lease extension plans.

The expense incurred during the first nine months of 2016 included proved properties of approximately $42.1 million of undeveloped leases that expired or are expected to expire without being developed, the majority of which were in Butler County, Pennsylvania and Warrior North in Ohio. Impairments of proved properties in our Butler County operations totaled approximately $1.1 million during the first nine months of 2016.

## 16. EXPLORATION EXPENSE

For the three and nine months ended September 30, 2017, exploration expenses for continuing operations incurred were approximately $0.1 million and $0.4 million, respectively, and approximately $0.2 million and $2.0 million for the three and nine months ended September 30, 2016, respectively. Approximately $0.3 million of the expense incurred in 2017 was due to geological and geophysical type expenditures and the remaining $0.1 million was due to delay rentals. Approximately $1.0 million of the expense incurred in 2016 was due to two exploratory wells that were abandoned at various stages, resulting in dry hole expense and the remaining 2016 expense of $1.0 million was due to geological and geophysical type expenditures.

## 17. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

As of September 30, 2017, we had $600.3 million aggregate principal amount of outstanding Senior Notes, as shown in Note 7, *Long-Term Debt*, to our Consolidated Financial Statements. The Senior Notes are guaranteed by certain of our wholly-owned subsidiaries, or guarantor subsidiaries. Unless otherwise noted below, each of the following guarantor subsidiaries are wholly-owned by Rex Energy Corporation and have provided guarantees of the Senior Notes that are joint and several and full and unconditional as of September 30, 2017:

- Rex Energy I, LLC;
- Rex Energy Operating Corporation;
- Rex Energy IV, LLC;
- PennTex Resources Illinois, Inc.; and
- R.E. Gas Development, LLC.

The non-guarantor subsidiaries include certain consolidated subsidiaries, including R.E. Disposal, LLC, Rex Energy Marketing, LLC and R.E. Ventures Holdings, LLC. We derive much of our business through and derive much of our income through our subsidiaries. Therefore, our ability to make required payments with respect to indebtedness and other obligations depends on the financial results and condition of our subsidiaries and our ability to receive funds from our subsidiaries. As of September 30, 2017, there were no restrictions on the ability of any of the guarantor subsidiaries to transfer funds to us. There may be restrictions for certain non-guarantor subsidiaries.

The following financial statements present condensed consolidating financial data for (i) Rex Energy Corporation, the issuer of the notes, (ii) the combined Guarantors, (iii) the combined other subsidiaries of the Company that did not guarantee the Notes, and (iv) eliminations necessary to arrive at our consolidated financial statements, which include condensed consolidated balance sheets as of September 30, 2017 and December 31, 2016, the condensed consolidating statements of operations for the three and nine months ended September 30, 2017 and 2016, and the condensed consolidating statements of cash flows for the nine months ended September 30, 2017 and 2016.

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING BALANCE SHEETS**
**AS OF SEPTEMBER 30, 2017**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **ASSETS** | | | | | |
| **Current Assets** | | | | | |
| Cash and Cash Equivalents | $ 3,231 | $ — | $ 3 | $ — | $ 3,234 |
| Accounts Receivable | 25,167 | — | — | — | 25,167 |
| Taxes Receivable | — | — | 48 | — | 48 |
| Short-Term Derivative Instruments | 3,443 | — | 461 | — | 3,904 |
| Inventory, Prepaid Expenses and Other | 2,903 | — | 621 | — | 3,524 |
| **Total Current Assets** | 34,744 | — | 1,133 | — | 35,877 |
| **Property and Equipment (Successful Efforts Method)** | | | | | |
| Evaluated Oil and Gas Properties | 1,022,857 | — | — | — | 1,022,857 |
| Unevaluated Oil and Gas Properties | 201,331 | — | — | — | 201,331 |
| Other Property and Equipment | 22,100 | — | — | — | 22,100 |
| Wells and Facilities in Progress | 46,814 | — | — | — | 46,814 |
| Pipelines | 16,803 | — | — | — | 16,803 |
| **Total Property and Equipment** | 1,309,905 | — | — | — | 1,309,905 |
| Less: Accumulated Depreciation, Depletion and Amortization | (452,882) | — | — | — | (452,882) |
| **Net Property and Equipment** | 857,023 | — | — | — | 857,023 |
| Other Assets | 2,475 | — | — | — | 2,475 |
| Intercompany Receivables | — | — | 1,048,592 | (1,048,592) | — |
| Investment in Subsidiaries – Net | (2,484) | — | (272,261) | 274,745 | — |
| Long-Term Derivative Instruments | 977 | — | 488 | — | 1,465 |
| **Total Assets** | $ 892,735 | $ — | $ 777,952 | $ (773,847) | $ 896,840 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | | | |
| **Current Liabilities** | | | | | |
| Accounts Payable | $ 48,221 | $ — | $ — | $ — | $ 48,221 |
| Current Maturities of Long-Term Debt | 1,859 | — | — | — | 1,859 |
| Accrued Liabilities | 31,433 | 434 | 3,866 | — | 35,733 |
| Short-Term Derivative Instruments | 12,477 | — | — | — | 12,477 |
| **Total Current Liabilities** | 93,990 | 434 | 3,866 | — | 98,290 |
| Long-Term Derivative Instruments | 13,486 | — | — | — | 13,486 |
| Term Loans, Net | — | — | 148,351 | — | 148,351 |
| Senior Notes, Net | — | — | 654,713 | — | 654,713 |
| Other Long-Term Debt | 8,615 | — | — | — | 8,615 |
| Other Deposits and Liabilities | 7,396 | — | — | — | 7,396 |
| Future Abandonment Cost | 9,025 | 2 | — | — | 9,027 |
| Intercompany Payables | 1,044,923 | 3,669 | — | (1,048,592) | — |
| **Total Liabilities** | 1,177,435 | 4,105 | 806,930 | (1,048,592) | 939,878 |
| **Stockholders' Equity** | | | | | |
| Preferred Stock | — | — | 1 | — | 1 |
| Common Stock | — | — | 10 | — | 10 |
| Additional Paid-In Capital | 177,144 | — | 652,055 | (177,144) | 652,055 |
| Accumulated Deficit | (461,844) | (4,105) | (681,044) | 451,889 | (695,104) |
| **Total Stockholders' Equity** | (284,700) | (4,105) | (28,978) | 274,745 | (43,038) |
| **Total Liabilities and Stockholders' Equity** | $ 892,735 | $ — | $ 777,952 | $ (773,847) | $ 896,840 |

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS**
**FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2017**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **OPERATING REVENUE** | | | | | |
| Natural Gas, NGL and Condensate Sales | $ 47,970 | $ — | $ — | $ — | $ 47,970 |
| Other Operating Revenue | 5 | — | — | — | 5 |
| **TOTAL OPERATING REVENUE** | 47,975 | — | — | — | 47,975 |
| **OPERATING EXPENSES** | | | | | |
| Production and Lease Operating Expense | 30,574 | — | — | — | 30,574 |
| General and Administrative Expense | 4,222 | — | 395 | — | 4,617 |
| Loss on Disposal of Assets | 252 | — | — | — | 252 |
| Impairment Expense | 11,877 | — | — | — | 11,877 |
| Exploration Expense | 94 | — | — | — | 94 |
| Depreciation, Depletion, Amortization and Accretion | 14,596 | 21 | — | — | 14,617 |
| Other Operating Expense | 449 | — | — | — | 449 |
| **TOTAL OPERATING EXPENSES** | 62,064 | 21 | 395 | — | 62,480 |
| **LOSS FROM OPERATIONS** | (14,089) | (21) | (395) | — | (14,505) |
| **OTHER INCOME (EXPENSE)** | | | | | |
| Interest Expense | (809) | — | (12,945) | — | (13,754) |
| Loss on Derivatives, Net | (17,989) | — | (94) | — | (18,083) |
| Other (Expense) Income | (201) | — | 16 | — | (185) |
| Loss on Extinguishments of Debt | — | — | (7) | — | (7) |
| (Loss) Income From Equity in Consolidated Subsidiaries | (21) | — | (33,109) | 33,130 | — |
| **TOTAL OTHER INCOME (EXPENSE)** | (19,020) | — | (46,139) | 33,130 | (32,029) |
| **(LOSS) INCOME BEFORE INCOME TAX** | (33,109) | (21) | (46,534) | 33,130 | (46,534) |
| Income Tax Benefit | — | — | — | — | — |
| **NET (LOSS) INCOME ATTRIBUTABLE TO REX ENERGY** | $ (33,109) | $ (21) | $ (46,534) | $ 33,130 | $ (46,534) |
| Preferred Stock Dividends | — | — | (598) | — | (598) |
| **NET (LOSS) INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS** | $ (33,109) | $ (21) | $ (47,132) | $ 33,130 | $ (47,132) |

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS**
**FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2017**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **OPERATING REVENUE** | | | | | |
| Natural Gas, NGL and Condensate Sales | $ 147,491 | $ — | $ — | $ — | $ 147,491 |
| Other Operating Revenue | 16 | — | — | — | 16 |
| **TOTAL OPERATING REVENUE** | 147,507 | — | — | — | 147,507 |
| **OPERATING EXPENSES** | | | | | |
| Production and Lease Operating Expense | 88,882 | — | — | — | 88,882 |
| General and Administrative Expense | 12,453 | — | 991 | — | 13,444 |
| Gain on Disposal of Assets | (1,707) | — | — | — | (1,707) |
| Impairment Expense | 16,455 | — | — | — | 16,455 |
| Exploration Expense | 413 | — | — | — | 413 |
| Depreciation, Depletion, Amortization and Accretion | 45,565 | 21 | — | — | 45,586 |
| Other Operating Expense | 331 | — | — | — | 331 |
| **TOTAL OPERATING EXPENSES** | 162,392 | 21 | 991 | — | 163,404 |
| **LOSS FROM OPERATIONS** | (14,885) | (21) | (991) | — | (15,897) |
| **OTHER INCOME (EXPENSE)** | | | | | |
| Interest Expense | (1,616) | — | (33,403) | — | (35,019) |
| Gain (Loss) on Derivatives, Net | 2,671 | — | (1,987) | — | 684 |
| Other (Expense) Income | (210) | — | 17 | — | (193) |
| Loss on Extinguishments of Debt | — | — | (3,029) | — | (3,029) |
| (Loss) Income From Equity in Consolidated Subsidiaries | (21) | | (14,061) | 14,082 | — |
| **TOTAL OTHER INCOME (EXPENSE)** | 824 | — | (52,463) | 14,082 | (37,557) |
| **(LOSS) INCOME BEFORE INCOME TAX** | (14,061) | (21) | (53,454) | 14,082 | (53,454) |
| Income Tax Benefit | — | — | — | — | — |
| **NET (LOSS) INCOME ATTRIBUTABLE TO REX ENERGY** | $ (14,061) | $ (21) | $ (53,454) | $ 14,082 | $ (53,454) |
| Preferred Stock Dividends | — | — | (1,794) | — | (1,794) |
| **NET (LOSS) INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS** | $ (14,061) | $ (21) | $ (55,248) | $ 14,082 | $ (55,248) |

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS**
**FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2017**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES** | | | | | |
| Net (Loss) Income | $ (14,061) | $ (21) | $ (53,454) | $ 14,082 | $ (53,454) |
| **Adjustments to Reconcile Net Loss to Net Cash Provided (Used) by Operating Activities** | | | | | |
| Depreciation, Depletion, Amortization and Accretion | 45,565 | 21 | — | — | 45,586 |
| (Gain) Loss on Derivatives, Net | (2,671) | — | 1,987 | — | (684) |
| Cash Settlements of Derivatives | (6,889) | — | — | — | (6,889) |
| Non-cash Dry Hole Expense | 13 | — | — | — | 13 |
| Equity-based Compensation Expense | 4 | — | 966 | — | 970 |
| Gain on Disposal of Assets | (1,707) | — | — | — | (1,707) |
| Loss on Extinguishments of Debt | — | — | 3,029 | — | 3,029 |
| Non-cash Interest Expense related to Debt Restructurings and Exchanges | — | — | 18,873 | — | 18,873 |
| Impairment Expense | 16,455 | — | — | — | 16,455 |
| Other Non-Cash Expense | 733 | — | — | — | 733 |
| **Changes in operating assets and liabilities** | | | | | |
| Accounts Receivable | 5,307 | — | 4 | — | 5,311 |
| Taxes Receivable | — | — | 163 | — | 163 |
| Inventory, Prepaid Expenses and Other Assets | (1,638) | — | (596) | — | (2,234) |
| Accounts Payable and Accrued Liabilities | (1,485) | — | — | — | (1,485) |
| Other Assets and Liabilities | (2,275) | — | — | — | (2,275) |
| **NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES** | 37,351 | — | (29,028) | 14,082 | 22,405 |
| **CASH FLOWS FROM INVESTING ACTIVITIES** | | | | | |
| Intercompany loans to subsidiaries | 13,537 | — | 545 | (14,082) | — |
| Proceeds from the Sale of Oil and Gas Properties, Prospects and Other Assets | 31,607 | — | — | — | 31,607 |
| Acquisitions of Undeveloped Acreage | (2,988) | — | — | — | (2,988) |
| Capital Expenditures for Development of Oil and Gas Properties and Equipment | (79,101) | — | — | — | (79,101) |
| **NET CASH (USED IN) PROVIDED BY INVESTING ACTIVITIES** | (36,945) | — | 545 | (14,082) | (50,482) |
| **CASH FLOWS FROM FINANCING ACTIVITIES** | | | | | |
| Proceeds from Long-Term Debt and Line of Credit | — | — | 183,000 | — | 183,000 |
| Repayments of Long-Term Debt and Line of Credit | — | — | (145,170) | — | (145,170) |
| Repayments of Loans and Other Long-Term Debt | (869) | — | — | — | (869) |
| Debt Issuance Costs | — | — | (8,151) | — | (8,151) |
| Payment of Preferred Dividends in Arrears | — | — | (1,196) | — | (1,196) |
| **NET CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES** | (869) | — | 28,483 | — | 27,614 |
| **NET DECREASE IN CASH** | (463) | — | — | — | (463) |
| **CASH – BEGINNING** | 3,694 | — | 3 | — | 3,697 |
| **CASH - ENDING** | $ 3,231 | $ — | $ 3 | $ — | $ 3,234 |

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING BALANCE SHEETS**
**AS OF DECEMBER 31, 2016**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **ASSETS** | | | | | |
| **Current Assets** | | | | | |
| Cash and Cash Equivalents | $ 3,694 | $ — | $ 3 | $ — | $ 3,697 |
| Accounts Receivable | 22,609 | — | 2,839 | — | 25,448 |
| Taxes Receivable | — | — | 211 | — | 211 |
| Short-Term Derivative Instruments | 650 | — | 1,223 | — | 1,873 |
| Inventory, Prepaid Expenses and Other | 2,521 | — | 25 | — | 2,546 |
| **Total Current Assets** | 29,474 | — | 4,301 | — | 33,775 |
| **Property and Equipment (Successful Efforts Method)** | | | | | |
| Evaluated Oil and Gas Properties | 1,053,461 | — | — | — | 1,053,461 |
| Unevaluated Oil and Gas Properties | 215,794 | — | — | — | 215,794 |
| Other Property and Equipment | 21,401 | — | — | — | 21,401 |
| Wells and Facilities in Progress | 21,964 | — | — | — | 21,964 |
| Pipelines | 18,029 | — | — | — | 18,029 |
| **Total Property and Equipment** | 1,330,649 | — | — | — | 1,330,649 |
| Less: Accumulated Depreciation, Depletion and Amortization | (475,205) | — | — | — | (475,205) |
| **Net Property and Equipment** | 855,444 | — | — | — | 855,444 |
| Other Assets | 2,492 | — | — | — | 2,492 |
| Intercompany Receivables | — | — | 1,035,713 | (1,035,713) | — |
| Investment in Subsidiaries – Net | (2,388) | — | (127,974) | 130,362 | — |
| Long-Term Derivative Instruments | 500 | — | 1,712 | — | 2,212 |
| **Total Assets** | $ 885,522 | $ — | $ 913,752 | $ (905,351) | $ 893,923 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | | | |
| **Current Liabilities** | | | | | |
| Accounts Payable | $ 40,712 | $ — | $ — | $ — | $ 40,712 |
| Current Maturities of Long-Term Debt | 764 | — | — | — | 764 |
| Accrued Liabilities | 32,328 | 421 | 4,458 | — | 37,207 |
| Short-Term Derivative Instruments | 25,025 | — | — | — | 25,025 |
| **Total Current Liabilities** | 98,829 | 421 | 4,458 | — | 103,708 |
| Long-Term Derivative Instruments | 7,227 | — | — | — | 7,227 |
| Senior Secured Line of Credit, Net | — | — | 113,785 | — | 113,785 |
| Term Loans. Net | — | — | — | — | — |
| Senior Notes, Net | — | — | 638,161 | — | 638,161 |
| Other Long-Term Debt | 3,409 | — | — | — | 3,409 |
| Other Deposits and Liabilities | 8,671 | — | — | — | 8,671 |
| Future Abandonment Cost | 8,736 | — | — | — | 8,736 |
| Intercompany Payables | 1,032,050 | 3,663 | — | (1,035,713) | — |
| **Total Liabilities** | 1,158,922 | 4,084 | 756,404 | (1,035,713) | 883,697 |
| **Stockholders' Equity** | | | | | |
| Preferred Stock | — | — | 1 | — | 1 |
| Common Stock | — | — | 10 | — | 10 |
| Additional Paid-In Capital | 177,144 | — | 650,669 | (177,144) | 650,669 |
| Accumulated Deficit | (450,544) | (4,084) | (493,332) | 307,506 | (640,454) |
| **Total Stockholders' Equity** | (273,400) | (4,084) | 157,348 | 130,362 | 10,226 |
| **Total Liabilities and Stockholders' Equity** | $ 885,522 | $ — | $ 913,752 | $ (905,351) | $ 893,923 |

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS**
**FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2016**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **OPERATING REVENUE** | | | | | |
| Natural Gas, NGL and Condensate Sales | $ 34,034 | $ — | $ — | $ — | $ 34,034 |
| Other Operating Expense | 5 | — | — | — | 5 |
| **TOTAL OPERATING REVENUE** | 34,039 | — | — | — | 34,039 |
| **OPERATING EXPENSES** | | | | | |
| Production and Lease Operating Expense | 26,333 | — | — | — | 26,333 |
| General and Administrative Expense | 4,114 | — | 1,002 | — | 5,116 |
| Loss on Disposal of Assets | 10 | — | — | — | 10 |
| Impairment Expense | 9,563 | — | — | — | 9,563 |
| Exploration Expense | 216 | — | — | — | 216 |
| Depreciation, Depletion, Amortization and Accretion | 15,109 | — | — | — | 15,109 |
| Other Operating Expense | 9,899 | — | — | — | 9,899 |
| **TOTAL OPERATING EXPENSES** | 65,244 | — | 1,002 | — | 66,246 |
| **LOSS FROM OPERATIONS** | (31,205) | — | (1,002) | — | (32,207) |
| **OTHER INCOME (EXPENSE)** | | | | | — |
| Interest Expense | (305) | — | (9,341) | — | (9,646) |
| Gain on Derivatives, Net | 16,866 | — | — | — | 16,866 |
| Other Income | 16 | — | — | | 16 |
| Debt Exchange Expense | — | — | (35) | — | (35) |
| Gain on Extinguishments of Debt | — | — | 423 | | 423 |
| Income (Loss) From Equity in Consolidated Subsidiaries | — | — | 12,087 | (12,087) | — |
| **TOTAL OTHER INCOME (EXPENSE)** | 16,577 | — | 3,134 | (12,087) | 7,624 |
| **(LOSS) INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX** | (14,628) | — | 2,132 | (12,087) | (24,583) |
| Income Tax Benefit | 4,823 | — | 3,283 | — | 8,106 |
| **NET (LOSS) INCOME FROM CONTINUING OPERATIONS** | (9,805) | — | 5,415 | (12,087) | (16,477) |
| Income From Discontinued Operations, Net of Income Taxes | 21,892 | — | — | — | 21,892 |
| **NET INCOME (LOSS)** | 12,087 | — | 5,415 | (12,087) | 5,415 |
| Preferred Stock Dividends | — | — | (613) | — | (613) |
| Effect of Preferred Stock Conversions | — | — | — | — | — |
| **NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS** | $ 12,087 | $ — | $ 4,802 | $ (12,087) | $ 4,802 |

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS**
**FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2016**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **OPERATING REVENUE** | | | | | |
| Natural Gas, Condensate and NGL Sales | $ 90,978 | $ — | $ — | $ — | $ 90,978 |
| Other Revenue | 12 | — | — | — | 12 |
| **TOTAL OPERATING REVENUE** | 90,990 | — | — | — | 90,990 |
| **OPERATING EXPENSES** | | | | | |
| Production and Lease Operating Expense | 76,004 | 1 | — | — | 76,005 |
| General and Administrative Expense | 13,193 | — | 2,044 | — | 15,237 |
| Gain on Disposal of Assets | (4,285) | — | — | — | (4,285) |
| Impairment Expense | 45,344 | — | — | — | 45,344 |
| Exploration Expense | 1,953 | 1 | — | — | 1,954 |
| Depreciation, Depletion, Amortization and Accretion | 46,358 | 13 | — | — | 46,371 |
| Other Operating Expense | 10,930 | — | — | — | 10,930 |
| **TOTAL OPERATING EXPENSES** | 189,497 | 15 | 2,044 | — | 191,556 |
| **LOSS FROM OPERATIONS** | (98,507) | (15) | (2,044) | — | (100,566) |
| **OTHER INCOME (EXPENSE)** | | | | | |
| Interest Expense | (844) | — | (33,271) | — | (34,115) |
| Loss on Derivatives, Net | (8,254) | — | — | — | (8,254) |
| Other Income | 28 | — | — | — | 28 |
| Debt Exchange Expense | — | — | (9,048) | — | (9,048) |
| Gain on Extinguishments of Debt | — | — | 24,130 | — | 24,130 |
| Income (Loss) From Equity in Consolidated Subsidiaries | 79 | (79) | (90,008) | 90,008 | — |
| **TOTAL OTHER INCOME (EXPENSE)** | (8,991) | (79) | (108,197) | 90,008 | (27,259) |
| **(LOSS) INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX** | (107,498) | (94) | (110,241) | 90,008 | (127,825) |
| Income Tax Benefit | 4,865 | — | 920 | — | 5,785 |
| **NET (LOSS) INCOME FROM CONTINUING OPERATIONS** | (102,633) | (94) | (109,321) | 90,008 | (122,040) |
| Income (Loss) From Discontinued Operations, Net of Income Taxes | 12,786 | (67) | — | — | 12,719 |
| **NET (LOSS) INCOME** | (89,847) | (161) | (109,321) | 90,008 | (109,321) |
| Preferred Stock Dividends | — | — | (4,441) | — | (4,441) |
| Effect of Preferred Stock Conversions | — | — | 72,316 | — | 72,316 |
| **NET (LOSS) INCOME ATTRIBUTABLE TO COMMON SHAREHOLDERS** | $ (89,847) | $ (161) | $ (41,446) | $ 90,008 | $ (41,446) |

**REX ENERGY CORPORATION AND SUBSIDIARIES**
**CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS**
**FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2016**
**($ in Thousands)**

| | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Rex Energy Corporation (Note Issuer) | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES** | | | | | |
| Net (Loss) Income | $ (89,847) | $ (161) | $ (109,321) | $ 90,008 | $ (109,321) |
| **Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities** | | | | | |
| Depreciation, Depletion, Amortization and Accretion | 51,456 | 15 | — | — | 51,471 |
| Loss on Derivatives, Net | 8,254 | — | — | — | 8,254 |
| Cash Settlements of Derivatives | 32,485 | — | — | — | 32,485 |
| Dry Hole Expense | 848 | 24 | — | — | 872 |
| Equity-based Compensation Expense | 32 | — | 1,899 | — | 1,931 |
| Gain on Disposal of Assets | (34,837) | 17 | — | — | (34,820) |
| Amortization of net Bond Discount and Deferred Debt Issuance Costs | — | — | 881 | — | 881 |
| Non-cash Interest Expense related to Debt Restructurings and Exchanges | — | — | 14,270 | — | 14,270 |
| Gain on Extinguishments of Debt | — | — | (24,213) | — | (24,213) |
| Impairment Expense | 48,887 | — | 48,887 | (48,887) | 48,887 |
| Other Non-Cash Expense | 61 | — | — | — | 61 |
| **Changes in operating assets and liabilities** | | | | | |
| Accounts Receivable | (21,121) | (346) | 18,887 | — | (2,580) |
| Inventory, Prepaid Expenses and Other Assets | 2,387 | — | (13) | — | 2,374 |
| Accounts Payable and Accrued Liabilities | (3,156) | — | (4,625) | — | (7,781) |
| Other Assets and Liabilities | (1,219) | (25) | — | — | (1,244) |
| **NET CASH (USED IN) PROVIDED BY OPERATING ACTIVITIES** | (5,770) | (476) | (53,348) | 41,121 | (18,473) |
| **CASH FLOWS FROM INVESTING ACTIVITIES** | | | | | |
| Intercompany loans to subsidiaries | 2,797 | 121 | 38,203 | (41,121) | — |
| Proceeds from the Sale of Oil and Gas Properties, Prospects and Other Assets | 40,347 | 462 | — | — | 40,809 |
| Proceeds from Joint Venture | 19,461 | — | — | — | 19,461 |
| Acquisitions of Undeveloped Acreage | (6,261) | (41) | — | — | (6,302) |
| Capital Expenditures for Development of Oil and Gas Properties and Equipment | (48,601) | (39) | — | — | (48,640) |
| **NET CASH PROVIDED BY (USED IN) INVESTING ACTIVITIES** | 7,743 | 503 | 38,203 | (41,121) | 5,328 |
| **CASH FLOWS FROM FINANCING ACTIVITIES** | | | | | |
| Proceeds from Long-Term Debt and Lines of Credit | — | — | 55,400 | — | 55,400 |
| Repayments of Long Term Debt and Lines of Credit | — | — | (35,230) | — | (35,230) |
| Repayments of Loans and Other Long-Term Debt | (541) | (27) | — | — | (568) |
| Debt Issuance Costs | — | — | (5,024) | — | (5,024) |
| **NET CASH (USED IN) PROVIDED BY FINANCING ACTIVITIES** | (541) | (27) | 15,146 | — | 14,578 |
| **NET INCREASE IN CASH** | 1,432 | — | 1 | — | 1,433 |
| **CASH – BEGINNING** | 1,089 | — | 2 | — | 1,091 |
| **CASH - ENDING** | $ 2,521 | $ — | $ 3 | $ — | $ 2,524 |

## Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

The following is management’s discussion and analysis of certain significant factors that have affected aspects of our financial position and results of operations during the periods included in the accompanying unaudited financial statements. You should read this in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the audited financial statements for the year ended December 31, 2016 included in our Annual Report on Form 10-K and the unaudited financial statements included elsewhere herein.

We use a variety of financial and operational measurements at interim periods to analyze our performance. These measurements include an analysis of production and sales revenue for the period; EBITDAX, a non-GAAP financial measurement; lease operating expenses per Mcf equivalent (“LOE per Mcfe”); and general and administrative (“G&A”) expenses per Mcfe.

### Overview of Our Business

We are an independent natural gas, NGL and condensate company operating in the Appalachian Basin, where we are focused on our Marcellus Shale, Utica Shale and Upper Devonian Shale drilling and exploration activities. We pursue a balanced growth strategy of exploiting our sizable inventory of high potential exploration drilling prospects while actively seeking to acquire complementary oil and natural gas properties. We are headquartered in State College, Pennsylvania, with a regional office in Cranberry, Pennsylvania.

We believe the outlook for our business is favorable despite the continued uncertainty of oil and gas prices. Our resource base, risk management, including an active hedging program, and disciplined investment of capital provide us with an opportunity to exploit and develop our positions and maximize efficiency in our key operating areas. We continue to focus on maintaining financial flexibility while pursuing an active, technology-driven drilling program to develop and maximize the value of our existing acreage as market conditions continue to evolve.

However, a prolonged period of depressed commodity prices could have a significant impact on the value and volumetric quantities of our proved reserves, and may result in write-downs of the carrying values of our oil and natural gas properties and revisions to our capital budget or development program. We discuss these matters in further detail under, among other places, “Commodity Prices,” “Impairment Expense,” “Capital Resources and Liquidity,” and “Volatility of Oil, NGL and Natural Gas Prices” below as well as in Note 15, “*Impairment Expense”*, to our Consolidated Financial Statements.

In June 2016, we entered into a purchase and sale agreement to divest all of our assets in the Illinois Basin. As of June 14, 2016, the Illinois Basin assets became classified as “Held for Sale” and our assets and operations of the Illinois Basin are reported as Discontinued Operations. Closing occurred on August 18, 2016, with an effective date for the transaction of July 1, 2016, in exchange for approximately $40.5 million in proceeds.

### 2017 Activity

During the three and nine months ended September 30, 2017, we produced 16,742 MMcfe and 48,458 MMcfe, respectively. Overall, our production for the three and nine months ended September 30, 2017 averaged 182 MMcfe per day and 178 MMcfe per day, respectively. As of September 30, 2017, we had 14.0 gross (11.3 net) wells drilled and awaiting completion. We had no wells resting or awaiting pipeline connection as of September 30, 2017. Our drilling and completion activity for the period indicated is set forth in the table below.

*Three and Nine Months Ended September 30, 2017 and 2016*

**Three Months Ended September 30, 2017**

| Wells Drilled | | Wells Completed | | Wells Placed In Service | |
|---|---|---|---|---|---|
| Gross | Net | Gross | Net | Gross | Net |
| 7.0 | 7.0 | 6.0 | 3.4 | 12.0 | 6.5 |

**Three Months Ended September 30, 2016**

| Wells Drilled | | Wells Completed | | Wells Placed In Service | |
|---|---|---|---|---|---|
| Gross | Net | Gross | Net | Gross | Net |
| 4.0 | 1.4 | 3.0 | 1.8 | 4.0 | 2.1 |

**Nine Months Ended September 30, 2017**

| Wells Drilled | | Wells Completed | | Wells Placed In Service | |
|---|---|---|---|---|---|
| Gross | Net | Gross | Net | Gross | Net |
| 21.0 | 15.6 | 16.0 | 7.9 | 16.0 | 7.9 |

**Nine Months Ended September 30, 2016**

| Wells Drilled | | Wells Completed | | Wells Placed In Service | |
|---|---|---|---|---|---|
| Gross | Net | Gross | Net | Gross | Net |
| 14.0 | 5.6 | 12.0 | 6.2 | 23.0 | 11.2 |

*Commodity Prices*

Our development plans are sensitive to current and projected commodity prices which have been and are expected to continue to be volatile. Our realized price, before derivative settlements, for natural gas during the three and nine months ended September 30, 2017, averaged approximately $2.52 per Mcf, and $2.87 Mcf, respectively, as compared to $1.54 per Mcf and $1.44 Mcf for the three and nine months ended September 30, 2016, respectively. Our realized price, before derivative settlements, for condensate during the three and nine months ended September 30, 2017, averaged approximately $42.00 per barrel and $43.58 per barrel, respectively, as compared to $38.82 per barrel and $34.72 per barrel for the three and nine months ended September 30, 2016, respectively. Our realized price, before derivative settlements, for C3+ NGLs during the three and nine months ended September 30, 2017 averaged approximately $29.62 per barrel and $27.82 per barrel, respectively, as compared to $16.48 per barrel and $14.74 per barrel for the three and nine months ended September 30, 2016, respectively. Our realized price, before derivative settlements, for ethane during the three and nine months ended September 30, 2017, averaged approximately $10.28 per barrel and $9.93 per barrel, respectively, and $7.99 per barrel and $7.28 per barrel as compared for the three and nine months ended September 30, 2016, respectively.

For the three and nine months ended September 30, 2017, we recorded impairment expense of approximately $11.9 million and $16.4 million, respectively. Decreases in commodity prices will decrease our natural gas, condensate and NGL revenues and could reduce the amount of natural gas, condensate and NGL reserves that we can economically produce. A prolonged period of depressed commodity prices or further declines in projected future commodity prices could require additional write-downs of the carrying values of our properties.

Because we follow the successful efforts method of accounting, our impairment tests are largely based on estimates of future commodity prices, changes in development and operating costs, taxes, operational efficiencies, changes in technology and access to capital, which makes predicting any future write-downs difficult and uncertain. In an effort to quantify the impact of continued low commodity pricing levels or further declines in future prices, we offer the following: as of September 30, 2017, approximately $499.1 million, or 84.7%, of our evaluated oil and natural gas properties were located in our Butler Marcellus operating area. Based on estimates of future cash flows, substantial further decreases in commodity prices combined with a lack of access to capital or a detrimental change to costs or operating efficiencies would need to occur in order for us to experience a write-down. Our remaining evaluated properties outside of the Butler Marcellus operating area are more sensitive to the current commodity price environment. These properties could experience additional write-downs if estimates of future commodity prices decline further. The net book value of these remaining evaluated properties totaled approximately $89.8 million as September 30, 2017.

*Debt for Equity Exchanges*

During the first nine months of 2017, we entered into privately negotiated debt-to-equity exchanges with certain holders of our Senior Notes in exchange for unrestricted shares of our common stock. These exchanges resulted in the retirement of approximately $0.9 million in the aggregate of our outstanding 8.875% Senior Notes due 2020, 6.25% Senior Notes due 2022 and 1.00/8.00% Senior Secured Second Lien Notes due 2020 (together, the “Senior Notes”), in exchange for the issuance of 83,626 shares of unrestricted common stock. The exchanged notes were subsequently cancelled, resulting in a gain of approximately $0.4 million, included as a component of *Gain (Loss) on Extinguishments of Debt* in our Consolidated Statement of Operations for the nine months ended September 30, 2017.

*Benefit Street Partners, LLC Joint Venture*

On March 1, 2016, we entered into a joint exploration and development agreement with an affiliate of Benefit Street Partners, LLC ("BSP") to jointly develop 58 specifically designated wells in our Moraine East and Warrior North operated areas. BSP agreed to participate in and fund 15.0% of the estimated well costs for 16 designated wells in Butler County, Pennsylvania, all of which have already been drilled, completed, placed in sales and paid for by BSP. BSP also agreed to participate in and fund 65.0% of the estimated well costs for six designated wells in Warrior North, Ohio, all of which have been drilled, completed, placed in sales and paid for by BSP. BSP also has the option to participate in the development of 36 additional wells and would fund 65.0% of the estimated well costs for the designated wells in return for a 65.0% working interest. To date, BSP has exercised its option to participate in 23 of these additional wells. Total consideration for this transaction could be up to $175.0 million with approximately $134.0 million committed as of September 30, 2017. BSP has paid approximately $128.3 million for its interest in elected wells as of September 30, 2017. The remainder of the proceeds will be received as additional wells are drilled to total depth or placed in sales. BSP earns an assignment of 15%-20% working interest in acreage located within each of the units in which it participates. As of September 30, 2017, 42 of the 45 committed wells were in line and producing, and three wells were drilled and awaiting completion.

**Results of Continuing Operations**

The following table sets forth summary information regarding NGL, condensate and natural gas production and product prices for the three and nine months ended September 30, 2017 and 2016:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Production: | | | | |
| Natural Gas (Mcf) | 10,299,872 | 10,927,477 | 30,101,503 | 33,559,096 |
| Condensate (Bbls) | 61,280 | 105,517 | 206,206 | 259,145 |
| C3+ NGLs (Bbls) | 464,929 | 498,217 | 1,326,076 | 1,495,961 |
| Ethane (Bbls) | 547,538 | 607,340 | 1,527,117 | 1,578,480 |
| Total (Mcfe)(a) | 16,742,354 | 18,193,921 | 48,457,897 | 53,560,612 |
| Average daily production: | | | | |
| Natural Gas (Mcf) | $ 111,955 | 118,777 | 110,262 | 122,478 |
| Condensate (Bbls) | 666 | 1,147 | 755 | 946 |
| C3+ NGLs (Bbls) | 5,054 | 5,415 | 4,857 | 5,460 |
| Ethane (Bbls) | 5,952 | 6,602 | 5,594 | 5,761 |
| Total (Mcfe)(a) | 181,982 | 197,760 | 177,501 | 195,480 |
| Average sales price(b): | | | | |
| Natural Gas (per Mcf) | $ 2.52 | $ 1.54 | $ 2.87 | $ 1.44 |
| Condensate (per Bbl) | $ 42.00 | $ 38.82 | $ 43.58 | $ 34.72 |
| C3+ NGLs (per Bbl) | $ 29.62 | $ 16.48 | $ 27.82 | $ 14.74 |
| Ethane (per Bbl) | $ 10.28 | $ 7.99 | $ 9.93 | $ 7.28 |
| Total (per Mcfe)(a) | $ 2.87 | $ 1.87 | $ 3.04 | $ 1.70 |
| Average NYMEX prices(c): | | | | |
| Oil (per Bbl) | $ 48.20 | $ 44.94 | $ 49.47 | $ 41.33 |
| Natural Gas (per Mcf) | $ 2.93 | $ 2.80 | $ 2.99 | $ 2.34 |

(a) Condensate, Ethane and C3+ NGLs are converted at the rate of one barrel of oil equivalent ("BOE") to six Mcfe.

(b) Does not include the effects of cash settled derivatives.

(c) Based upon the average of bid week prompt month prices.

The following table sets forth summary information regarding NGL, condensate and natural gas revenues, production volumes, average product prices and average production costs for the three and nine months ended September 30, 2017 and 2016:

| | Production and Revenue by Product | | | |
|---|---|---|---|---|
| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | 2017 | 2016 | 2017 | 2016 |
| Revenue – Natural Gas(a) | $ 25,996,738 | $ 16,871,451 | $ 86,438,411 | $ 48,431,297 |
| Volumes (Mcf) | 10,299,872 | 10,927,477 | 30,101,503 | 33,559,096 |
| Average Price | $ 2.52 | $ 1.54 | $ 2.87 | $ 1.44 |
| Revenue – Condensate (a) | $ 2,573,526 | $ 4,096,017 | $ 8,987,039 | $ 8,998,352 |
| Volumes (Bbl) | 61,280 | 105,517 | 206,206 | 259,145 |
| Average Price | $ 42.00 | $ 38.82 | $ 43.58 | $ 34.72 |
| Revenue – C3+ NGLs(a) | $ 13,769,585 | $ 8,210,863 | $ 36,896,251 | $ 22,053,201 |
| Volumes (Bbl) | 464,929 | 498,217 | 1,326,076 | 1,495,961 |
| Average Price | $ 29.62 | $ 16.48 | $ 27.82 | $ 14.74 |
| Revenue – Ethane(a) | $ 5,629,768 | $ 4,855,353 | $ 15,169,958 | $ 11,494,780 |
| Volumes (Bbl) | 547,538 | 607,340 | 1,527,117 | 1,578,480 |
| Average Price | $ 10.28 | $ 7.99 | $ 9.93 | $ 7.28 |
| Average Production Cost per Mcfe(b) | $ 1.82 | $ 1.43 | $ 1.83 | $ 1.40 |

(a) Does not include the effects of cash settled derivatives.

(b) Excludes ad valorem and severance taxes.

*General Overview*

Operating revenue for the three and nine months ended September 30, 2017 increased 40.9% and 62.1% when compared to the same periods in 2016, respectively. The increase in operating revenue for the three and nine months ended September 30, 2017 can be primarily attributed to higher natural gas, condensate and NGL prices, offset partially by lower production volumes. Our production decreased to 16,742 MMcfe for the three month period ended September 30, 2017, from 18,194 MMcfe for the three month period ended September 30, 2016, or approximately 8.0%. For the nine months ended September 30, 2017, our production decreased 9.5% to 53,561 MMcfe from the nine months ended September 30, 2016. For the three month period ended September 30, 2017, our realized sales price for natural gas increased to $2.52 per Mcf from $1.54 per Mcf, condensate increased to $42.00 per barrel from $38.82 per barrel, C3+ NGLs increased to $29.62 per barrel from $16.48 per barrel, and ethane increased to $10.28 per barrel from $7.99 per barrel, respectively, when compared to the same period in 2016. For the nine months ended September 30, 2017, our realized sales price for natural gas increased to $2.87 per Mcf from $1.44 per Mcf, condensate increased to $43.58 per barrel from $34.72 per barrel, C3+ NGLs increased to $27.82 per barrel from $14.74 per barrel, and ethane increased to $9.93 per barrel from $7.28 per barrel, respectively, when compared to the same period in 2016.

Operating expenses decreased $3.8 million and $28.2 million, respectively, for the three and nine months ended September 30, 2017, as compared to the same periods in 2016. Operating expenses primarily comprise: Production and Lease Operating Expenses, G&A Expenses, Other Operating Expense, Exploration Expenses, Impairment Expense and DD&A Expenses. The decreases in operating expenses were largely attributable to fewer impairment charges during the nine-month period, a decrease in other income/expense and lower G&A expenses, net of higher Lease Operating Expenses. The decrease of many of these operating expenses is consistent with the overall decrease in activity within the industry in conjunction with a decrease in the cost of goods and services and other cost control measures that we have implemented. The decrease in impairment was largely indicative of the increase in commodity prices as compared to prices realized during the three and nine months ended September 30, 2016.

*Comparison of the Three Months Ended September 30, 2017 to the Three Months Ended September 30, 2016*

**Gas, condensate and NGL revenue**, including the effects of cash settled derivatives, for the three-month periods ended September 30, 2017 and 2016 is summarized in the following table:

| ($ in Thousands, except total Mcfe production and price per Mcfe) | For the Three Months Ended September 30, 2017 | 2016 | Change | % |
|---|---|---|---|---|
| Gas sales revenue | $ 25,997 | $ 16,871 | $ 9,126 | 54.1% |
| Gas derivatives realized(a) | $ 1,432 | $ 1,200 | $ 232 | 19.3% |
| Total gas revenue and derivatives realized | $ 27,429 | $ 18,071 | $ 9,358 | 51.8% |
| Condensate sales revenue | $ 2,574 | $ 4,096 | $ (1,522) | (37.2)% |
| Oil and condensate derivatives realized(a) | $ 151 | $ 93 | $ 58 | 62.4% |
| Total condensate revenue and derivatives realized | $ 2,725 | $ 4,189 | $ (1,464) | (34.9)% |
| C3+ NGL revenue | $ 13,770 | $ 8,211 | $ 5,559 | 67.7% |
| C3+ NGL derivatives realized(a) | $ (2,871) | $ 830 | $ (3,701) | (445.9)% |
| Total C3+ NGL revenue | $ 10,899 | $ 9,041 | $ 1,858 | 20.6% |
| Ethane revenue | $ 5,630 | $ 4,855 | $ 775 | 16.0% |
| Ethane derivatives realized(a) | $ (77) | $ 97 | $ (174) | (179.8)% |
| Total Ethane revenue | $ 5,553 | $ 4,952 | $ 602 | 12.1% |
| Consolidated sales | $ 47,971 | $ 34,033 | $ 13,938 | 41.0% |
| Consolidated derivatives realized(a) | $ (1,365) | $ 2,220 | $ (3,585) | (161.5)% |
| Total NGL, condensate and gas revenue and derivatives realized | $ 46,606 | $ 36,253 | $ 10,354 | 28.6% |
| Total Mcfe Production | 16,742,354 | 18,193,921 | (1,451,567) | (8.0)% |
| Average Realized Price per Mcfe | $ 2.78 | $ 1.99 | $ 0.79 | 39.7% |

(a) Realized derivatives are included in Other Income (Expense) on our Consolidated Statements of Operations.

**Average realized price** received for natural gas, condensate and NGLs during the third quarter of 2017, after the effect of derivative activities, was $2.78 per Mcfe, an increase of 39.7%, or $0.79 per Mcfe, from the same period in 2016. This increase was primarily due to an increase in commodity prices during the quarter driven by increased sales to the Gulf Coast and improved northeast basis differentials, partially offset by cash-settled losses on derivatives. The average price for natural gas, after the effect of derivative activities, increased 61.0%, or $1.01 per Mcf, to $2.66 per Mcf. The average price for condensate, after the effect of derivative activities, increased 12.0%, or $4.77 per barrel, to $44.47 per barrel. The average price for C3+ NGLs, after the effect of derivative activities, increased 29.2%, or $5.30 per barrel, to $23.44 per barrel. The average price for ethane, after the effect of derivative activities, increased 24.4%, or $1.99 per barrel, to $10.14 per barrel. Our derivative activities effectively decreased net realized prices by $0.08 per Mcfe in the third quarter of 2017 and increased net realized prices by $0.12 per Mcfe in the third quarter of 2016.

Our realized sales price for natural gas was lower than the average Henry Hub NYMEX pricing by approximately $0.27 per Mcf during the third quarter of 2017, primarily due to basis differentials in the northeastern United States, which were partially offset by sales to the Gulf Coast, which receive Henry Hub NYMEX pricing. We have been able to stabilize the impact of basis differentials to an extent by utilizing basis swaps in our derivatives program. In addition, we have been targeting sales points outside of the northeastern United States and have executed capacity agreements to transport natural gas volumes to the Midwest and the Gulf Coast, including transportation of 100,000 Mcf per day to the Gulf Coast that began during the fourth quarter of 2016.

**Production volumes** in the third quarter of 2017 decreased 8.0%, or 1,451.6 MMcfe, from the third quarter of 2016 primarily due to the sale of our Warrior South assets during first quarter of 2017. Natural gas production decreased approximately 5.7%, condensate production decreased approximately 41.9%, C3+ NGL production decreased approximately 6.7% and our ethane production decreased approximately 9.8%.

Overall, our production for the third quarter of 2017 averaged 181,982 Mcfe per day, of which 61.5% was attributable to natural gas, 2.2% to condensate, 16.7% to C3+ NGLs and 19.6% was a result of ethane production.

Statements of Operations for the three months ended September 30, 2017 and 2016 are as follows:

| ($ in Thousands) | For the Three Months Ended September 30, 2017 | 2016 | Change | % |
|---|---|---|---|---|
| **OPERATING REVENUE** | | | | |
| Natural Gas, NGL and Condensate Sales | $ 47,970 | $ 34,034 | $ 13,936 | 40.9% |
| Other Operating Revenue | 5 | 5 | — | (—)% |
| **TOTAL OPERATING REVENUE** | 47,975 | 34,039 | 13,936 | 40.9% |
| **OPERATING EXPENSES** | | | | |
| Production and Lease Operating Expense | 30,574 | 26,333 | 4,241 | 16.1% |
| General and Administrative Expense | 4,617 | 5,116 | (499) | (9.8)% |
| Loss on Disposal of Assets | 252 | 10 | 242 | 2,420.0% |
| Impairment Expense | 11,877 | 9,563 | 2,314 | 24.2% |
| Exploration Expense | 94 | 216 | (122) | (56.5)% |
| Depreciation, Depletion, Amortization and Accretion | 14,617 | 15,109 | (492) | (3.3)% |
| Other Operating Expense | 449 | 9,899 | (9,450) | (95.5)% |
| **TOTAL OPERATING EXPENSES** | 62,480 | 66,246 | (3,766) | (5.7)% |
| **LOSS FROM OPERATIONS** | (14,505) | (32,207) | 17,702 | (55.0)% |
| **OTHER INCOME (EXPENSE)** | | | | |
| Interest Expense | (13,754) | (9,646) | (4,108) | 42.6% |
| (Loss) Gain on Derivatives, Net | (18,083) | 16,866 | (34,949) | (207.2)% |
| Other (Expense) Income | (185) | 16 | (201) | (1,256.3)% |
| Debt Exchange Expense | — | (35) | 35 | (100.0)% |
| (Loss) Gain on Extinguishments of Debt | (7) | 423 | (430) | (101.7)% |
| **TOTAL OTHER INCOME (EXPENSE)** | (32,029) | 7,624 | (39,653) | (520.1)% |
| **LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAX** | (46,534) | (24,583) | (21,951) | 89.3% |
| Income Tax Benefit | — | 8,106 | (8,106) | (100.0)% |
| **NET LOSS FROM CONTINUING OPERATIONS** | (46,534) | (16,477) | (30,057) | 182.4% |
| Income From Discontinued Operations, Net of Income Taxes | — | 21,892 | (21,892) | (100.0)% |
| **NET (LOSS) INCOME** | $ (46,534) | $ 5,415 | $ (51,949) | (959.4)% |

**Production and Lease Operating Expense** increased approximately $4.2 million, or 16.1%, in the third quarter of 2017 from the same period in 2016. We experienced Production and Lease Operating Expense increases that are commensurate with the increase in producing wells, firm capacity expense related to additional avenues in delivering our products and variable costs such as transportation, marketing, processing and gathering. Transportation, marketing, processing and gathering fees accounted for approximately 91.0% of our total Production and Lease Operating Expense in the third quarter of 2017, as compared to 87.0% from the same period in 2016. As we continue to develop our core areas of operation we expect that fees incurred from unutilized commitments will decrease. These types of agreements typically have a term of several years and we expect fees associated with these agreements to continue to comprise a significant portion of our Production and Lease Operating Expense. On a per unit of production basis, our lifting costs were $1.83 and $1.45 per Mcfe for the three months ended September 30, 2017 and 2016, respectively. The increase on a per unit basis is related to the commencement of our Gulf Coast transportation agreement, which carries a higher transportation cost to access pricing that is premium to the northeast markets.

**G&A Expense** for the third quarter of 2017 decreased approximately $0.5 million, or 9.8%, to $4.6 million from the same period in 2016**.** The decrease was mostly due to the forfeiture of restricted stock, which was approximately $0.5 million.

**Impairment Expense** for the third quarter of 2017 was approximately $11.9 million. We evaluate impairment of our properties when events occur that indicate that the carrying value of these properties may not be recoverable. The expense incurred during the third quarter of 2017 included $3.1 million of undeveloped leases that expired or are expected to expire without being developed, the majority of which are in Butler County, Pennsylvania, and Warrior North in Ohio. Based on the current commodity price environment, we do not expect to develop these properties prior to expiration of the associated leases. Impairment of proved properties in our Butler County operations totaled approximately $8.7 million during the third quarter of 2017. The impairments were identified through an analysis of market conditions and future development plans related to these properties that were in existence as of September 30, 2017, which indicated that the full carrying value of the assets was not recoverable. The analysis included an evaluation of estimated future cash flows with consideration given to market prices for similar assets. Any amount of future impairments are difficult to predict, however, if commodity prices decline, downward revisions of proved reserves may be significant and could result in additional impairment expense.

**Exploration Expense** for the third quarter of 2017 was approximately $0.1 million, as compared to $0.2 million for same period in 2016. The expense incurred in 2017 was mostly due to geological and geophysical type expenditures. Approximately $0.2 million of the expense incurred in 2016 was due to delay rentals and geological and geophysical type expenditures.

**DD&A Expense** for the third quarter of 2017 decreased approximately $0.5 million, or 3.3%, from $15.1 million for the same period in 2016. Contributing to the decrease in DD&A expense was an overall decrease in production, including the sale of our Warrior South assets in the first quarter of 2017.

**Other Operating Expense** for the third quarter of 2017 decreased approximately $9.4 million from $9.9 million for the same period in 2016. The expense in 2016 was primarily related to a firm transportation contract associated with an area west of our core assets in Butler County, Pennsylvania.

**Interest Expense** for the third quarter of 2017 was approximately $13.8 million as compared to $9.6 million for the same period in 2016. The increase in interest expense is primarily due to interest charges incurred on the term loan and fees charged on available but undrawn borrowing base of the Term Loan Delayed Draws established in April 2017. The increase is partially offset by a decrease in semi-annual bond interest payments due to our Senior Note exchanges. We discuss our Term Loan and Senior Notes in Note 7, *Long-Term Debt*, to our Consolidated Financial Statements.

**Gain (Loss) on Derivatives, net** included a loss of approximately $18.1 million for the third quarter of 2017 as compared to a gain of $16.9 million for the same period in 2016. The loss recorded for the third quarter of 2017 included cash payments for commodity derivatives of $1.4 million while the gain incurred in the third quarter of 2016 included cash receipts of approximately $2.1 million for commodity derivatives. Changes were attributable to the volatility of oil, NGL and natural gas commodity prices along with changes in our portfolio of outstanding derivatives. Losses from derivative activities generally reflect higher oil, NGL and natural gas prices in the marketplace than were in effect at the end of the last period while gains generally reflect the opposite. Our derivative program is designed to provide us with greater reliability of future cash flows at expected levels of oil, NGL and gas production volumes given the highly volatile oil, NGL and gas commodities market.

We believe oil, NGL and natural gas prices will remain volatile and could decline further. Although we have entered into derivative contracts covering a portion of our production volumes for the remainder of 2017 and 2018, a sustained lower price environment would result in lower prices for unprotected volumes and reduce the prices that we can enter into derivative contracts for additional volumes in the future.

**Gain (Loss) on Extinguishments of Debt** for the third quarter of 2017 was a minimal loss. Gain on extinguishments of debt for the third quarter of 2016 totaled approximately $0.4 million, resulting from debt to equity exchanges with certain holders of our Senior Notes. We discuss the debt to equity exchanges in Note 7, *Long-Term Debt*, to our Consolidated Financial Statements.

**Income Tax Expense** for continuing operations for the third quarter of 2017 was zero, due to the full valuation allowances we maintain against our net deferred tax assets.

For the third quarter of 2016, income tax benefit was $8.1 million. Our estimated annual effective tax rate for 2016 differed from the U.S. statutory rate of 35.0% primarily due to the effect of having full valuation allowances recorded against our deferred tax assets coupled with recognizing tax benefits in continuing operations for the effect of taxable income generated by our discontinued operations. To a lesser extent, the annual effective rate is also influenced by alternative minimum tax with no corresponding deferred tax benefit due to the full valuation allowance, and state taxes in certain tax paying jurisdictions. Our alternative minimum tax due for 2016 was driven primarily by cancellation of debt income of $543.2 million related to the Senior Note exchanges.

**Net Income (Loss) Attributable to Rex Energy** for the third quarter of 2017 was a loss of approximately $46.5 million, as compared to income of $4.8 million for the same period in 2016 as a result of factors discussed above.

*Comparison of the Nine Months Ended September 30, 2017 to the Nine Months Ended September 30, 2016*

**Gas, condensate and NGL revenue**, including the effects of cash settled derivatives, for the nine-month periods ended September 30, 2017 and 2016 is summarized in the following table:

| ($ in Thousands, except total Mcfe production and price per Mcfe) | For the Nine Months Ended September 30, 2017 | 2016 | Change | % |
|---|---|---|---|---|
| Gas sales revenue | $ 86,438 | $ 48,431 | $ 38,007 | 78.5% |
| Gas derivatives realized(a) | $ (1,333) | $ 24,280 | $ (25,613) | (105.5)% |
| Total gas revenue and derivatives realized | $ 85,105 | $ 72,711 | $ 12,394 | 17.0% |
| Condensate sales revenue | $ 8,987 | $ 8,998 | $ (11) | (0.1)% |
| Oil and condensate derivatives realized(a) | $ 297 | $ 2,191 | $ (1,894) | (86.4)% |
| Total condensate revenue and derivatives realized | $ 9,284 | $ 11,189 | $ (1,905) | (17.0)% |
| C3+ NGL revenue | $ 36,896 | $ 22,053 | $ 14,843 | 67.3% |
| C3+ NGL derivatives realized(a) | $ (5,872) | $ 6,040 | $ (11,912) | (197.2)% |
| Total C3+ NGL revenue | $ 31,024 | $ 28,093 | $ 2,931 | 10.4% |
| Ethane revenue | $ 15,170 | $ 11,495 | $ 3,675 | 32.0% |
| Ethane derivatives realized(a) | $ 19 | $ 241 | $ (222) | (92.1)% |
| Total Ethane revenue | $ 15,189 | $ 11,736 | $ 3,453 | 29.4% |
| Consolidated sales | $ 147,491 | $ 90,977 | $ 56,514 | 62.1% |
| Consolidated derivatives realized(a) | $ (6,889) | $ 32,752 | $ (39,641) | (121.0)% |
| Total NGL, condensate and gas revenue and derivatives realized | $ 140,602 | $ 123,729 | $ 16,873 | 13.6% |
| Total Mcfe Production | 48,457,897 | 53,560,612 | (5,102,715) | (9.5)% |
| Average Realized Price per Mcfe | $ 2.90 | $ 2.31 | $ 0.59 | 25.6% |

(a) Realized derivatives are included in Other Income (Expense) on our Consolidated Statements of Operations.

**Average realized price** received for natural gas, condensate and NGLs during the first nine months of 2017 after the effect of derivative activities, was $2.90 per Mcfe, an increase of 25.6%, or $0.59 per Mcfe, from the same period in 2016. This increase was primarily due to an increase in commodity prices during the first nine months of 2017 driven by increased sales to the Gulf Coast and improved northeast basis differentials, partially offset by cash-settled losses on derivatives. The average price for natural gas, after the effect of derivative activities, increased 30.5%, or $0.66 per Mcf, to $2.83 per Mcf. The average price for condensate, after the effect of derivative activities, increased 4.3%, or $1.85 per barrel, to $45.02 per barrel. The average price for C3+ NGLs, after the effect of derivative activities, increased 24.6%, or $4.62 per barrel, to $23.40 per barrel. The average price for ethane, after the effect of derivative activities, increased 33.8%, or $2.51 per barrel, to $9.95 per barrel. Our derivative activities effectively decreased net realized prices by $0.14 per Mcfe during the first nine months of 2017 and increased net realized prices by $0.61 per Mcfe during the first nine months of 2016.

Our realized sales price for natural gas was lower than the average Henry Hub NYMEX pricing by approximately $0.12 per Mcf during the first nine months of 2017, primarily due to basis differentials in the northeastern United States, which were partially offset by sales to the Gulf Coast, which receive Henry Hub NYMEX pricing. We have been able to stabilize the impact of basis differentials to an extent by utilizing basis swaps in our derivatives program. In addition, we have been targeting sales points outside of the northeastern United States and have executed capacity agreements to transport natural gas volumes to the Midwest and the Gulf Coast, including transportation of 100,000 Mcf per day to the Gulf Coast that began during the fourth quarter of 2016.

**Production volumes** in the first nine months of 2017 decreased 9.5%, or 5,102.7 MMcfe, from the first nine months of 2016, primarily due to the sale of our Warrior South assets during first quarter of 2017. Natural gas production decreased approximately 10.3%, condensate production decreased approximately 20.4%, C3+ NGL production decreased approximately 11.4% and our ethane production decreased approximately 3.3%.

Overall, our production for the first nine months of 2017 averaged 177,501 Mcfe per day, of which 62.1% was attributable to natural gas, 2.6% to condensate, 16.4% to C3+ NGLs and 18.9% was a result of ethane production.

Statements of Operations for the nine-month periods ended September 30, 2017 and 2016 are as follows:

| ($ in Thousands) | For the Nine Months Ended September 30, 2017 | 2016 | Change | % |
|---|---|---|---|---|
| **OPERATING REVENUE** | | | | |
| Natural Gas, Condensate and NGL Sales | $ 147,491 | $ 90,978 | $ 56,513 | 62.1% |
| Other Operating Revenue | 16 | 12 | 4 | 33.3% |
| **TOTAL OPERATING REVENUE** | 147,507 | 90,990 | 56,517 | 62.1% |
| **OPERATING EXPENSES** | | | | |
| Production and Lease Operating Expense | 88,882 | 76,005 | 12,877 | 16.9% |
| General and Administrative Expense | 13,444 | 15,237 | (1,793) | (11.8)% |
| Gain on Disposal of Assets | (1,707) | (4,285) | 2,578 | (60.2)% |
| Impairment Expense | 16,455 | 45,344 | (28,889) | (63.7)% |
| Exploration Expense | 413 | 1,954 | (1,541) | (78.9)% |
| Depreciation, Depletion, Amortization and Accretion | 45,586 | 46,371 | (785) | (1.7)% |
| Other Operating Expense | 331 | 10,930 | (10,599) | (97.0)% |
| **TOTAL OPERATING EXPENSES** | 163,404 | 191,556 | (28,152) | (14.7)% |
| **LOSS FROM OPERATIONS** | (15,897) | (100,566) | 84,669 | (84.2)% |
| **OTHER INCOME (EXPENSE)** | | | | |
| Interest Expense | (35,019) | (34,115) | (904) | 2.6% |
| Gain (Loss) on Derivatives, Net | 684 | (8,254) | 8,938 | (108.3)% |
| Other (Expense) Income | (193) | 28 | (221) | (789.3)% |
| Debt Exchange Expense | — | (9,048) | 9,048 | (100.0)% |
| (Loss) Gain on Extinguishments of Debt | (3,029) | 24,130 | (27,159) | (112.6)% |
| **TOTAL OTHER EXPENSE** | (37,557) | (27,259) | (10,298) | 37.8% |
| **LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAX** | (53,454) | (127,825) | 74,371 | (58.2)% |
| Income Tax Benefit | — | 5,785 | (5,785) | (100.0)% |
| **NET LOSS FROM CONTINUING OPERATIONS** | (53,454) | (122,040) | 68,586 | (56.2)% |
| Income From Discontinued Operations, Net of Income Taxes | — | 12,719 | (12,719) | (100.0)% |
| **NET INCOME (LOSS)** | (53,454) | (109,321) | 55,867 | (51.1)% |

**Production and Lease Operating Expense** increased approximately $12.9 million, or 16.9%, during the first nine months of 2017 from the same period in 2016. We experienced Production and Lease Operating Expense increases that are commensurate with the increase in producing wells and related production as they relate to variable costs such as transportation, marketing, processing and gathering. Transportation, marketing, processing and gathering fees accounted for approximately 90.6% of our total Production and Lease Operating Expense during the first nine months of 2017, as compared to 87.1% from the same period in 2016. As we continue to develop our core areas of operation we expect that fees incurred from unutilized commitments will decrease. These types of agreements typically have a term of several years and we expect fees associated with these agreements to continue to comprise a significant portion of our Production and Lease Operating Expense. On a per unit of production basis, our lifting costs were $1.83 and $1.42 per Mcfe for the nine months ended September 30, 2017 and 2016, respectively. The increase on a per unit basis is related to the commencement of our Gulf Coast transportation agreement, which carries a higher transportation cost to access pricing that is premium to the northeast markets.

**G&A Expense** for the first nine months of 2017 decreased approximately $1.8 million, or 11.8%, to $13.4 million from the same period in 2016. The decrease was mostly due to a decrease in transactional fees associated with the BSP transaction of $0.4 million during the first nine months of 2017 as compared to $1.4 million during same period in 2016. Also contributing to the decrease in G&A was the forfeiture of restricted stock, which reduced expense by approximately $1.0 million.

**Impairment Expense** for the first nine months of 2017 was approximately $16.5 million. We evaluate impairment of our properties when events occur that indicates that the carrying value of these properties may not be recoverable. The expense incurred during the first nine months of 2017 included $7.0 million of undeveloped leases that expired or are expected to expire without being developed, the majority of which are in Butler County, Pennsylvania, and Warrior North in Ohio. Based on the current commodity price environment, we do not expect to develop these properties prior to expiration of the associated leases. Impairment of proved properties in our Butler County operations totaled approximately $9.4 million during the first nine months of 2017. The impairments were identified through an analysis of market conditions and future development plans related to these properties that were in existence as of September 30, 2017, which indicated that the carrying value of the assets was not recoverable. The analysis included an evaluation of estimated future cash flows with consideration given to market prices for similar assets. Any amount of future impairments are difficult to predict, however, if commodity prices decline, downward revisions of proved reserves may be significant and could result in additional impairment expense.

**Exploration Expense** for the first nine months of 2017 was approximately $0.4 million, as compared to $2.0 million for the same period in 2016. Approximately $0.3 million of the expense incurred in 2017 was due to geological and geophysical type expenditures and the remaining $0.1 million was due to delay rental payments. Approximately $1.1 million of the expense incurred in 2016 was due to geological and geophysical type expenditures and $0.9 million was due to costs associated with exploratory wells that were abandoned at various stages, resulting in dry hole expense. As a result of the decrease in commodity prices, we have decreased our levels of spending with regards to geological and geophysical activities.

**DD&A Expense** for the first nine months of 2017 decreased approximately $0.8 million, or 1.7%, from $46.4 million for the same period in 2016. Contributing to the decrease in DD&A expense was an overall decrease in production, including the sale of our Warrior South assets in the first quarter of 2017.

**Other Operating Expense** for the first nine months of 2017 decreased approximately $10.6 million from $10.9 million for the same period in 2016. The expense in 2016 was primarily related to a firm transportation contract associated with an area west of our core assets in Butler County, Pennsylvania. During the third quarter of 2016, we elected to cease all future development activities in the area associated with this contract and recorded $8.3 million to Other Operating Expense, representing the expense equal to the present value of our full future obligations under the contract.

**Interest Expense** for the nine months ended September 30, 2017 was approximately $35.0 million as compared to $34.1 million for the same period in 2016. The increase in interest expense is primarily due to interest charges incurred on the term loan and fees charged on available but undrawn borrowing base of the Term Loan Delayed Draws established in April 2017 and a decrease in interest expense capitalized to evaluated properties in 2017, offset partially by the reduced bond interest expense as a result of the Senior Notes exchange completed on March 31, 2016. We discuss our Senior Notes, term loan and revolving credit facility in Note 7, *Long-Term Debt*, to our Consolidated Financial Statements.

**Gain (Loss) on Derivatives, net** included a gain of approximately $0.7 million for the first nine months of 2017 as compared to a loss of $8.3 million for the same period in 2016. The gain recorded for the first nine months of 2017 included cash payments for commodity derivatives of $6.9 million while the loss incurred in the first half of 2016 included cash receipts of approximately $32.5 million for commodity derivatives. Changes were attributable to the volatility of oil, NGL and natural gas commodity prices along with changes in our portfolio of outstanding derivatives. Losses from derivative activities generally reflect higher oil, NGL and natural gas prices in the marketplace than were in effect at the end of the last period while gains generally reflect the opposite. Our derivative program is designed to provide us with greater reliability of future cash flows at expected levels of oil, NGL and gas production volumes given the highly volatile oil, NGL and gas commodities market.

We believe oil, NGL and natural gas prices will remain volatile and could decline further. Although we have entered into derivative contracts covering a portion of our production volumes for the remainder of 2017 and 2018, a sustained lower price environment would result in lower prices for unprotected volumes and reduce the prices that we can enter into derivative contracts for additional volumes in the future.

**Gain (Loss) on Extinguishments of Debt** for the nine months ended September 30, 2017 totaled a loss of approximately $3.0 million. The loss in 2017 reflects the write-off of approximately $3.4 million of unamortized debt issuance costs related to the Senior Credit Facility retired in April 2017, offset by approximately $0.4 million in gains from debt to equity exchanges completed in the nine months ended September 30, 2017. Gain on extinguishments of debt for the nine months ended September 30, 2016 totaled approximately $24.1 million, resulting from debt to equity exchanges with certain holders of our Senior Notes. We discuss the debt to equity exchanges in Note 7, *Long-Term Debt*, to our Consolidated Financial Statements.

**Income Tax Expense** for continuing operations for the first nine months of 2017 was zero, due to the full valuation allowances we maintain against our net deferred tax assets.

For the first nine months of 2016, income tax expense was $5.8 million. Our estimated annual effective tax rate for 2016 differed from the U.S. statutory rate of 35.0% primarily due to the effect of having full valuation allowances recorded against our deferred tax assets coupled with recognizing tax benefits in continuing operations for the effect of taxable income generated by our discontinued operations. To a lesser extent, the annual effective rate is also influenced by alternative minimum tax with no corresponding deferred tax benefit due to the full valuation allowance, and state taxes in certain tax paying jurisdictions. Our alternative minimum tax due for 2016 was driven primarily by cancellation of debt income of $543.2 million related to the Senior Note exchanges.

**Net Loss Attributable to Rex Energy** for the first nine months of 2017 was approximately $53.5 million, as compared to $109.3 million for the same period in 2016 as a result of factors discussed above.

| | Other Performance Measurements | | | |
|---|---|---|---|---|
| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
| | 2017 | 2016 | 2017 | 2016 |
| EBITDAX from Continuing Operations ($ in Thousands) (a) | $ 11,939 | $ 4,536 | $ 39,936 | $ 32,031 |
| LOE per Mcfe | $ 1.83 | $ 1.45 | $ 1.83 | $ 1.42 |
| G&A per Mcfe | $ 0.28 | $ 0.28 | $ 0.28 | $ 0.28 |

(a) EBITDAX is a non-GAAP measure. See "Non-GAAP Financial Measures" for our reconciliation of EBITDAX to net income.

*EBITDAX (Non-GAAP)*

EBITDAX (Non-GAAP) from continuing operations increased approximately $7.9 million to $39.9 million for the nine-month period ended September 30, 2017, as compared to the same period in 2016. The increase in EBITDAX can be primarily attributed to the increased average sales prices for natural gas, NGLs and condensate, resulting in increased operating revenues, offset primarily by decreases in production and a decrease in cash receipts related to derivatives.

*LOE per Mcfe*

LOE per Mcfe measures the average cost of extracting natural gas, condensate and NGLs from our reserves during the period. This measurement is also commonly referred to in the industry as our "lifting cost". It represents the average cost of extracting one Mcf of natural gas equivalent from our natural gas and NGL reserves in the ground. LOE per Mcfe increased $0.38 to $1.83 for the three months ended September 30, 2017 as compared to $1.45 for the same period in 2016. LOE per Mcfe increased $0.41 to $1.83 for the nine months ended September 30, 2017, as compared to $1.42 for the same period in 2016. The increase in our LOE per Mcfe in each period can be attributed to our Gulf Coast transportation, which began in November 2016, which carries a heavier transportation burden while providing premium natural gas pricing. Our LOE is largely composed of variable type costs such as transportation, marketing, processing and gathering. For the third quarter of 2017, transportation, capacity and processing fees accounted for approximately 91.0% of our total Production and Lease Operating Expense as compared to 87.0% during the same period of 2016. For the nine months ended September 30, 2017, transportation, capacity and processing fees accounted for approximately 90.6% of our total Production and Lease Operating Expense as compared to 87.1% during the same period of 2016. These agreements typically have a term of several years, and we expect them to continue to comprise a significant portion of our Production and Lease Operating Expense. Various agreements that we have entered into include firm capacity rights, for which we may incur a fee for unused capacity. As we continue to grow our operations, we expect our lifting cost to decrease as we gain additional efficiencies of scale and utilize all of our firm capacity and transportation commitments.

*G&A Expenses per Mcfe*

Our G&A expenses include fees for well operating services, marketing, non-field level employee compensation and related benefits, office and lease expenses, insurance costs and professional fees, as well as other costs and expenses not directly related to field operations. Our management continually evaluates the level of our G&A expenses in relation to our production because these expenses have a direct impact on our profitability. G&A expenses per Mcfe were approximately $0.28 for the three month period ended September 30, 2017, as compared to $0.28 for the same period in 2016. During the first nine months of 2017, G&A per Mcfe was approximately $0.28 as compared to $0.28 for the same period of 2016. The decreases in G&A costs in 2017 that offset the decrease in volume are predominately due to reduced transactional costs during the first half of 2017 as compared to transactional costs associated with the BSP transaction during same period in 2016.

**Capital Resources and Liquidity**

On April 28, 2017, we entered into a Term Loan Credit Agreement (the "Term Loan") and subsequently terminated and repaid amounts outstanding under our revolving credit facility (for additional information, see Note 7, Long Term Debt, to our Consolidated Financial Statements).

Our primary needs for cash are for the exploration, development and acquisition of oil and gas properties. During the nine months ended September 30, 2017, we spent $82.1 million of capital on asset acquisitions, drilling projects, facilities and related equipment and acquisitions of unproved acreage. We funded our capital program with proceeds from the sale of our Warrior South assets, proceeds from the Term Loan, cash from operations and joint venture reimbursements received from BSP. The remainder of our 2017 capital budget is expected to be funded primarily by cash on hand, cash flows from operations, proceeds from the Term Loan and potential future asset sales and joint ventures.

Our cash flows from operations are driven by commodity prices and production volumes. Prices for oil, NGLs and gas are driven by, among other things, seasonal influences of weather, national and international economic and political environments and, increasingly, from national and global supply and demand for hydrocarbons. Our working capital is significantly influenced by changes in commodity prices, and significant declines in prices could decrease our exploration and development expenditures. Historically, we have primarily used cash flows from operations, borrowings from lines of credit and net proceeds from debt and equity offerings to fund the exploration and development of our oil and gas interests. As of September 30, 2017, we had approximately $3.2 million of cash on hand and outstanding borrowings under our Term Loan of approximately $155.5 million with an additional $32.2 million of undrawn letters of credit outstanding. As of September 30, 2017, we had approximately $112.3 million of undrawn availability on the Term Loan.

Our ability to fund our capital expenditure program is dependent upon the level of commodity prices and the success of our exploration programs in replacing our existing natural gas, NGL and condensate reserves. If commodity prices decrease, our operating cash flows may decrease, which could reduce funds available to fund our capital expenditure program. The effects of commodity prices on cash flows can be mitigated through the use of commodity derivatives. If we are unable to replace our natural gas, NGL and condensate reserves through acquisitions and our development and exploration programs, we may also suffer a reduction in our operating cash flows and access to funds under our Term Loan. We expect to be in compliance with all required debt covenants for at least the twelve month period following the filing date of our Form 10-Q report for the quarterly reporting period ended September 30, 2017.

Due to the depressed commodity price environment, in January 2016, we suspended payment of our quarterly dividend on shares of our Series A Convertible, Perpetual Preferred Stock ("Preferred Stock"). We have the ability to continue to suspend dividend payments and will continue to evaluate the payment of these dividends on a quarterly basis. In April and July 2017, we declared a quarterly dividend of $0.6 million, based on $150.00 per share on our Preferred Stock ($1.50 per depositary share, each representing 1/100 interest in a share of Preferred Stock) payable on May 15, 2017 and August 15, 2017, respectively; each dividend payment was applied to the earliest dividend in arrears at the time of payment. In October 2017, we declared a quarterly dividend in the same amount; this dividend payment will be made in stock on November 15, 2017, and will be applied to the earliest dividend still in arrears at the time of payment. Any subsequent quarterly dividends declared and paid will be applied to the earliest dividend then in arrears until the arrearage is satisfied and dividends are current. As a result of having dividends in arrears on our Preferred Stock, we are not currently eligible to use Form S-3 registration statements. Until we are again eligible to use Form S-3, we will be required to use a registration statement on Form S-1 to register public offerings of securities with the SEC (for initial issuance or resale) or issue securities in private placements, which could increase the cost of raising capital.

We may need to take additional actions in the future to address current industry trends and maintain our ability to pay expenses and service our indebtedness, including, but not limited to, selling assets or raising capital by issuing additional debt or equity securities.

We have outstanding Senior Notes that are governed by indentures with substantially similar terms and provisions (the "Indentures"). The Indentures contain affirmative and negative covenants that are customary for instruments of this nature, including restrictions or limitations on our ability to incur additional debt, pay dividends, purchase or redeem stock or subordinated indebtedness, make investments, create liens, sell assets, merge with or into other companies or transfer substantially all of our assets, unless those actions satisfy the terms and conditions of the Indentures or are otherwise excepted or permitted. Certain of the limitations in the Indentures, including our ability to incur debt, pay dividends or make other restricted payments, become more restrictive in the event our ratio of consolidated cash flow to fixed charges for the most recent trailing four quarters (the "Fixed Charge Coverage Ratio") is less than 2.25 to 1.00. As of September 30, 2017, our Fixed Charge Coverage Ratio was 1.24 to 1.00. We expect our Fixed Charge Coverage Ratio to improve in 2017 and beyond based on our projections of decreased interest expense related to our Senior Notes, increased production and improved price realizations. As of September 30, 2017, we were limited to incurring approximately $134.9 million in additional debt due to our Fixed Charge Coverage Ratio. The Indentures also contain customary events of default, including cross-default features with any other indebtedness. In certain circumstances, the Trustee or the holders of the Senior Notes may declare all outstanding notes to be due and payable immediately.

We were not restricted as to our borrowings under our Term Loan; however we are subject to the minimum financial requirements detailed in Note 7, *Long-Term Debt*, to our Consolidated Financial Statements. If we are unable to comply with these financial requirements, an event of default could result which would permit acceleration of outstanding debt and could permit our lenders to foreclose on our mortgaged properties.

***Future Liquidity Considerations***

In connection with certain of our marketing, transportation and processing agreements that we have entered into, we may be obligated to pay minimum fees in connection with these agreements of $194.4 million over the next five years, depending on our levels of production. In connection with certain of these agreements, we concurrently entered into a guaranty whereby we have guaranteed the payment of obligations under the specified agreements up to a maximum of $384.4 million over the life of the agreements. These guarantees will decrease over time as the commitments are satisfied.

Our Term Loan contains a number of restrictive covenants and limitations that impose significant operating and financial restrictions on us. Our financial covenants require us to maintain a maximum “Ratio of Net Senior Secured Debt to EBITDAX” of 3.25 to 1.0, a minimum “Ratio of EBITDAX to Interest Expense” of 1.0 to 1.0, increasing to 1.3 to 1.0 for quarterly periods ending on or after March 31, 2018 and a minimum “PDP Coverage Ratio” of 1.65 to 1.00. Failure to comply with these covenants could have a material adverse effect on our business. As of September 30, 2017, our Net Senior Secured Debt to EBITDAX Ratio was 2.85 to 1.00 and EBITDAX to Interest Expense ratio was 2.88 to 1.00. If an event of default under our Term Loan occurs and remains uncured, among other things, the lenders thereunder:

- Would not be required to lend any additional amounts to us;
- Could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- May have the ability to require us to apply all of our available cash to repay these borrowings; or
- May prevent us from making debt service payments under our other agreements.

In order to improve our liquidity positions to meet the financial requirements under our Term Loan and to meet other outstanding obligations, we are currently pursuing or considering a number of actions, which in certain cases may involve current investors, affiliates of the Company, or other financing or strategic counterparties, including (i) debt-for-debt or debt-for-equity exchanges, (ii) joint venture opportunities, (iii) minimizing capital expenditures, (iv) improving cash flows from operations, (v) effectively managing working capital, (vi) adding hedging positions, (vii) asset sales, and (viii) in- and out-of-court restructuring transactions. There can be no assurance that sufficient liquidity can be raised from any one or more of these transactions or that these transactions can be consummated within the period needed to meet our obligations.

**Financial Condition and Cash Flows for the nine months ended September 30, 2017 and 2016**

The following table summarizes our sources and uses of funds for the periods noted:

| | Nine Months Ended September 30, | |
|---|---|---|
| ($ in Thousands) | **2017** | **2016** |
| Cash flows provided by (used in) operations | $ 22,405 | $ (18,473) |
| Cash flows (used in) provided by investing activities | (50,482) | 5,328 |
| Cash flows provided by financing activities | 27,614 | 14,578 |
| Net (decrease) increase in cash and cash equivalents | $ (463) | $ 1,433 |

**Net cash provided by operating activities** during the first nine months of 2017 increased $40.9 million from net cash used by operating activities during the same period in 2016. This was primarily due to increases in realized prices of our natural gas, condensate and C3+ NGL sales, and decreased cash interest outflow of approximately $17.5 million as a result of our debt restructuring events in 2016, partially offset by decreased production and settlement of derivatives.

**Net cash used in investing activities** during the first nine months of 2017 increased $58.8 million from net cash provided by investing activities during the same period in 2016. This was due to capital development expenditures in the first nine months of 2017 that were approximately $30.5 million higher than in the first nine months of 2016, coupled with the effect of joint venture capital reimbursements of approximately $19.4 million we received in 2016, reducing our net capital expenditure outflow in the first nine months of 2016. These factors account for a net increase in cash used in investing activities of $49.9 million for the first nine months of 2017 compared to the first nine months of 2016.

**Net cash provided by financing activities** during the first nine months of 2017 increased by approximately $13.0 million from net cash provided by financing activities during the same period in 2016, primarily due to borrowings made on our new Term Loan, this was partially offset by debt issuance costs and preferred stock dividends.

As market conditions warrant and subject to our contractual restrictions in the Term Loan, our Indentures or otherwise, liquidity position and other factors, we may from time to time seek to recapitalize, refinance or otherwise restructure our capital structure in open market or privately negotiated transactions, which may include, among other things, repurchases of outstanding equity securities or outstanding debt, including our Senior Notes, by tender offer, exchange or otherwise. The amounts involved in any such transaction, individually or in the aggregate, may be material.

**Effects of Inflation and Changes in Price**

Our results of operations and cash flows are affected by changing oil, NGL and natural gas prices. If the price of oil, NGLs and natural gas increases or decreases, there could be a corresponding increase or decrease in the operating cost that we are required to bear for operations, as well as an increase or decrease in revenues.

**Critical Accounting Policies and Recently Adopted Accounting Pronouncements**

During the quarter ended September 30, 2017, there were no material changes to the critical accounting policies previously reported by us in our Annual Report on Form 10-K for the year ended December 31, 2016. We describe critical recently adopted and issued accounting standards in Part I, Item 1. Financial Statements—Note 5, "Recently Issued Accounting Pronouncements."

**Non-GAAP Financial Measures**

***EBITDAX***

"EBITDAX" means, for any period, the sum of net income for such period plus the following expenses, charges or income to the extent deducted from or added to net income in such period: interest, income taxes, DD&A, unrealized losses from financial derivatives, exploration expenses and other similar non-cash charges, minus all non-cash income, including but not limited to, income from unrealized financial derivatives, added to net income. EBITDAX, as defined above, is used as a financial measure by our management team and by other users of its financial statements, such as our commercial bank lenders to analyze such things as:

- Our operating performance and return on capital in comparison to those of other companies in our industry, without regard to financial or capital structure;
- The financial performance of our assets and valuation of the entity without regard to financing methods, capital structure or historical cost basis;
- Our ability to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our stockholders; and
- The viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDAX is not a calculation based on GAAP financial measures and should not be considered as an alternative to net income (loss) (the most directly comparable GAAP financial measure) in measuring our performance, nor should it be used as an exclusive measure of cash flows, because it does not consider the impact of working capital growth, capital expenditures, debt principal reductions, and other sources and uses of cash, which are disclosed in our consolidated statements of cash flows.

We have reported EBITDAX because it is a financial measure used by our existing commercial lenders, and because this measure is commonly reported and widely used by investors as an indicator of a company's operating performance and ability to incur and service debt. You should carefully consider the specific items included in our computations of EBITDAX. While we have disclosed EBITDAX to permit a more complete comparative analysis of our operating performance and debt servicing ability relative to other companies, you are cautioned that EBITDAX as reported by us may not be comparable in all instances to EBITDAX as reported by other companies. EBITDAX amounts may not be fully available for management's discretionary use, due to requirements to conserve funds for capital expenditures, debt service and other commitments.

We believe that EBITDAX assists our lenders and investors in comparing our performance on a consistent basis without regard to certain expenses, which can vary significantly depending upon accounting methods. Because we may borrow money to finance our operations, interest expense is a necessary element of our costs. In addition, because we use capital assets, DD&A are also necessary elements of our costs. Finally, we are required to pay federal and state taxes, which are necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations.

To compensate for these limitations, we believe it is important to consider both net income determined under GAAP and EBITDAX to evaluate our performance.

The following table presents a reconciliation of our net income to EBITDAX for each of the periods presented:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| ($ in Thousands) | 2017 | 2016 | 2017 | 2016 |
| Net Loss From Continuing Operations | $ (46,534) | $ (16,477) | $ (53,454) | $ (122,040) |
| Add Back Non-Recurring Costs[1] | 765 | 8,306 | 4,224 | (6,388) |
| Add Back Depletion, Depreciation, Amortization and Accretion | 14,617 | 15,109 | 45,586 | 46,371 |
| Add Back Non-Cash Compensation Expense | 395 | 990 | 966 | 2,006 |
| Add Back Interest Expense | 13,754 | 9,646 | 35,019 | 34,115 |
| Add Back Impairment Expense | 11,877 | 9,563 | 16,455 | 45,344 |
| Add Back Exploration Expenses | 94 | 216 | 413 | 1,954 |
| Add Back (Less) (Gain) Loss on Disposal of Assets | 252 | 10 | (1,707) | (4,285) |
| Less (Gain) Loss on Financial Derivatives | 18,083 | (16,866) | (684) | 8,254 |
| Add Back (Less) Cash Settlement of Derivatives | (1,365) | 2,145 | (6,889) | 32,485 |
| Less Income Tax Benefit | — | (8,106) | — | (5,785) |
| EBITDAX From Continuing Operations | $ 11,938 | $ 4,536 | $ 39,929 | $ 32,031 |
| Net Income From Discontinued Operations | $ — | $ 21,892 | $ — | $ 12,719 |
| Add Back Depletion, Depreciation, Amortization and Accretion | — | 18 | — | 5,100 |
| Add Back Non-Cash Compensation Expense | — | (366) | — | (107) |
| Add Back Interest Expense | — | 1 | — | 4 |
| Add Back Impairment Expense | — | — | — | 3,543 |
| Add Back Exploration Expenses | — | — | — | 143 |
| Less Gain on Disposal of Assets | — | (30,491) | — | (30,535) |
| Add Back Income Tax Expense | — | 8,354 | — | 7,852 |
| Add EBITDAX From Discontinued Operations | $ — | $ (592) | $ — | $ (1,281) |
| EBITDAX (Non-GAAP) | $ 11,938 | $ 3,944 | $ 39,929 | $ 30,750 |

1 For the three months ended September 30, 2017, includes a net $0.2 million of advisory services related to an engineering study and $0.5 million in non-recurring legal and insurance costs. For the nine months ended September 30, 2017, includes a net $0.6 million of advisory services related to our joint venture drilling programs and an engineering study, $0.5 million in non-recurring legal and insurance costs and $3.0 million in loss on the extinguishment of debt. For the three months ended September 30, 2016, includes approximately $8.3 million in expense related to firm transportation contract. For the nine months ended September 30, 2016, includes approximately $24.1 million in gains on extinguishment of debt, net of $8.3 million in expense related to firm transportation contract and $9.0 million in debt exchange expenses.

**Volatility of Oil, NGL and Natural Gas Prices**

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil, NGLs and natural gas. We account for our natural gas and oil exploration and production activities under the successful efforts method of accounting. To mitigate some of our commodity price risk, we engage periodically in certain other limited derivative activities including price swaps and costless collars in order to establish some price floor protection.

For the three and nine months ended September 30, 2017, we paid net settlements on oil, NGL and natural gas derivatives of approximately $1.3 million and $6.9 million, respectively, as compared to receiving net settlements of approximately $2.2 million and $32.8 million for the same period in 2016. These gains and losses are reported as Gain (Loss) on Derivatives, Net in our Consolidated Statements of Operations. As of September 30, 2017, we had over 75.0% and 50.0% of our annualized condensate production hedged through the remainder of 2017 and 2018, respectively, over 90.0% and 65.0% of our annualized natural gas production hedged through the remainder of 2017 and 2018, respectively, and over 65.0% and 55.0% of our annualized NGL production hedged through the remainder of 2017 and 2018, respectively. These percentages exclude the effects of our basis swaps and do not include any estimated impact of increased production from future drilling and completion activity or the natural decline of our natural gas, condensate and NGL production.

Our primary sources of production and revenue are located in the Appalachian Basin. Natural gas prices in the Appalachian Basin are exposed to regional basis differentials when compared to NYMEX pricing. During the nine months ended September 30, 2017, our average realized prices for natural gas were lower than the average NYMEX prices over the same period by approximately $0.12 per Mcf. We have been able to stabilize the impact of basis differentials to an extent by utilizing basis swaps in our derivatives program. We have Dominion South basis swaps in place for 3,355 MMcf at an average differential to Henry Hub NYMEX of $0.81 per Mcf for the remainder of 2017 in addition to Dominion South basis swaps for 12,775 MMcf at an average differential to Henry Hub NYMEX of $0.83 per Mcf for 2018. For the nine months ended September 30, 2017, we paid cash settlements on our basis differential derivatives of approximately $1.4 million.

While the use of derivative arrangements limits the downside risk of adverse price movements, it may also limit our ability to benefit from increases in the prices of oil, NGLs and natural gas. We have entered into the majority of our derivatives transactions with two counterparties and have a netting agreement in place with our counterparties. While we do not obtain collateral to support the agreements, we do monitor the financial viability of our counterparties and believe our credit risk is minimal on these transactions. Under these arrangements, payments are received or made based on the differential between a fixed and a variable commodity price. These agreements are settled in cash at expiration or exchanged for physical delivery contracts. In the event of nonperformance, we would be exposed again to price risk. We have additional risk of financial loss because the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the derivative transaction. Moreover, our derivatives arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivatives will vary from time to time.

For a summary of our oil, NGL and natural gas derivative positions at September 30, 2017, refer to Part I, Item 1. Financial Statements - Note 8, *"Derivative Instruments and Fair Value Measurements"*.

*Contractual Obligations*

In addition to our capital expenditure program, we are committed to making cash payments in the future on various types of contracts and obligations. Our contractual obligations include long-term debt, operating leases, operational commitments, other loans and notes payable, derivative obligations, firm commitments under sales, gathering and processing agreements and asset retirement obligations. Since December 31, 2016, there have been no material changes to our contractual obligations, other than an increase in long-term debt due to our borrowings under the former Senior Credit Facility and current Term Loan. See Part I, Item 1. Financial Statements—Note 7, "*Long-Term Debt"* for additional information on the Senior Credit Facility and Term Loan.

*Off-Balance Sheet Arrangements*

We do not currently use any off-balance sheet arrangements to enhance our liquidity or capital resource position, or for any other purpose.

**Item 3. Quantitative and Qualitative Disclosures about Market Risk.**

We are exposed to various market risks, including energy commodity price risk. We expect energy prices to remain volatile and unpredictable. If energy prices were to decrease for a substantial period of time or decline significantly, revenues and cash flows would significantly decline, and our ability to borrow to finance our operations could be adversely impacted. Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil, NGLs and natural gas. Conversely, increases in the market prices for oil, NGLs and natural gas can have a favorable impact on our financial condition, results of operations and capital resources**.** Based on production through September 30, 2017, we project that a 10% decline in the price per barrel of oil and NGLs and the price per Mcf of gas from the first nine months of 2017 average would reduce our gross revenues, before the effects of derivatives, for the remaining three months of 2017 by approximately $14.7 million.

We have designed our hedging program to reduce the risk of price volatility for our production in the oil, NGL and natural gas markets. Our risk management policy provides for the use of derivative instruments to manage these risks. The types of derivative instruments that we use include swaps, collars, put spreads, put options, basis swaps, swaptions and three way collars. The volume of derivative instruments that we may use are governed by the risk management policy and can vary from year to year, but under most circumstances will apply to only a portion of our current and anticipated production, and will provide only partial price protection against declines in oil, NGL and natural gas prices. We are exposed to market risk on our open contracts, to the extent of changes in market prices of oil, NGLs and natural gas. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged. Further, if our counterparties should default, this protection might be limited as we might not receive the benefits of the hedges.

At September 30, 2017, we had the following commodity derivative contracts outstanding:

| Period | Volume | | Put Option | Floor | Ceiling | Swap | Fair Market Value ($ in Thousands) |
|---|---|---|---|---|---|---|---|
| *Oil* | | | | | | | |
| 2017 - Swaps | 15,000 | Bbls | $ — | $ — | $ — | $ 54.00 | $ 30 |
| 2017 - Three-Way Collars | 39,000 | Bbls | 39.62 | 49.23 | 61.35 | — | 34 |
| 2018 - Swaps | 60,000 | Bbls | — | — | — | 54.00 | 120 |
| 2018 - Collars | 18,000 | Bbls | — | 53.00 | 60.00 | — | 56 |
| 2018 - Three-Way Collars | 66,000 | Bbls | 42.08 | 51.59 | 61.55 | — | 93 |
| 2019 - Swaps | 31,500 | Bbls | — | — | — | 51.00 | 4 |
| 2019 - Collars | 60,250 | Bbls | — | 45.00 | 55.07 | — | (11) |
| 2019 - Three-Way Collars | 24,000 | Bbls | 37.50 | 47.50 | 58.39 | — | 3 |
| 2020 - Swaps | 24,000 | Bbls | — | — | — | 51.00 | 4 |
| 2020 - Collars | 71,750 | Bbls | | 45.00 | 55.10 | — | (14) |
| 2020 - Three-Way Collars | 3,000 | Bbls | 37.50 | 47.50 | 59.00 | — | 2 |
| 2021 - Swaps | 6,000 | Bbls | — | — | — | 51.00 | 1 |
| 2021 - Collars | 63,750 | Bbls | — | 45.00 | 55.02 | — | (15) |
| 2022 - Collars | 36,000 | Bbls | — | 45.00 | 54.75 | — | (11) |
| | 518,250 | Bbls | | | | | $ 296 |
| *Natural Gas* | | | | | | | |
| 2017 - Swaps | 2,540,000 | Mcf | — | — | — | 3.12 | $ 306 |
| 2017 - Swaptions | 600,000 | Mcf | — | — | — | 3.33 | 161 |
| 2017 - Cap Swaps | 900,000 | Mcf | 2.35 | — | — | 2.81 | (314) |
| 2017 - Collars | 500,000 | Mcf | — | 2.88 | 3.43 | — | 34 |
| 2017 - Three-Way Collars | 4,550,000 | Mcf | 2.29 | 2.98 | 3.86 | — | 326 |
| 2017 - Calls | 750,000 | Mcf | — | — | 3.64 | — | (59) |
| 2017 - Basis Swaps - Dominion South | 3,355,000 | Mcf | — | — | — | (0.81) | (343) |
| 2017 - Basis Swaps - Texas Gas | 3,680,000 | Mcf | — | — | — | (0.13) | 38 |
| 2018 - Swaps | 15,335,000 | Mcf | — | — | — | 3.10 | 779 |
| 2018 - Swaptions | — | Mcf | — | — | — | — | (117) |
| 2018 - Three-Way Collars | 10,600,000 | Mcf | 2.33 | 2.90 | 3.52 | — | 155 |
| 2018 - Calls | 5,810,000 | Mcf | — | — | 3.97 | — | (384) |
| 2018 - Collars | 450,000 | Mcf | — | 3.20 | 3.65 | — | 52 |
| 2018 - Basis Swaps - Dominion South | 12,775,000 | Mcf | — | — | — | (0.83) | (2,916) |
| 2018 - Basis Swaps - Texas Gas | 14,600,000 | Mcf | — | — | — | (0.13) | 150 |
| 2019 - Swaps | 10,470,000 | Mcf | — | — | — | 2.84 | (281) |
| 2019 - Three-Way Collars | 8,205,000 | Mcf | 2.27 | 2.77 | 3.40 | — | 10 |
| 2019 - Collars | 4,580,000 | Mcf | — | 2.50 | 3.05 | — | (124) |
| 2019 - Basis Swaps - Dominion South | 12,775,000 | Mcf | — | — | — | (0.84) | (3,217) |
| 2020 - Swaps | 4,560,000 | Mcf | — | — | — | 2.87 | (292) |
| 2020 - Three-Way Collars | 4,555,000 | Mcf | 2.23 | 2.73 | 3.30 | — | (8) |
| 2020 - Collars | 4,115,000 | Mcf | — | 2.50 | 3.05 | — | (165) |
| 2020 - Basis Swaps - Dominion South | 7,320,000 | Mcf | — | — | — | (0.84) | (1,900) |
| 2021 - Swaps | 3,875,000 | Mcf | — | — | — | 2.77 | (162) |
| 2021 - Three-Way Collars | 3,037,500 | Mcf | 2.17 | 2.67 | 3.15 | — | (56) |
| 2021 - Collars | 2,737,500 | Mcf | — | 2.50 | 3.05 | — | (165) |
| 2021 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| 2022 - Swaps | 2,730,000 | Mcf | — | — | — | 2.73 | (89) |
| 2022 - Three-Way Collars | 2,047,500 | Mcf | 2.15 | 2.65 | 3.10 | — | (54) |
| 2022 - Collars | 2,047,500 | Mcf | — | 2.50 | 3.05 | — | (124) |
| 2022 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| 2023 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| 2024 - Basis Swaps - Dominion South | 3,650,000 | Mcf | — | — | — | (0.72) | (701) |
| | 164,100,000 | Mcf | | | | | $ (11,563) |
| *NGLs* | | | | | | | |
| 2017 - C3+ NGL Swaps | 409,000 | Bbls | — | — | — | 29.22 | $ (4,847) |
| 2017 - Ethane Swaps | 225,000 | Bbls | — | — | — | 10.58 | (214) |
| 2018 - C3+ NGL Swaps | 1,125,072 | Bbls | — | — | — | 31.93 | (4,156) |
| 2018 - Ethane Swaps | 1,150,000 | Bbls | — | — | — | 12.95 | 494 |
| 2019 - C3+ NGL Swaps | 392,814 | Bbls | — | — | — | 28.61 | (1,097) |
| 2019 - C5 Collars | 113,040 | Bbls | — | 45.00 | 54.83 | — | (38) |
| 2019 - Ethane Swaps | 595,000 | Bbls | — | — | — | 13.06 | 159 |
| 2020 - C3+ NGL Swaps | 261,228 | Bbls | — | — | — | 37.11 | (395) |
| 2020 - C5 Collars | 28,260 | Bbls | — | 45.00 | 54.83 | — | (10) |
| 2020 - Ethane Swaps | 356,000 | Bbls | — | — | — | 12.89 | (35) |
| 2021 - C3+ NGL Swap | 133,620 | Bbls | — | — | — | 44.72 | (85) |
| 2021 - Ethane Swaps | 175,000 | Bbls | — | — | — | 12.84 | (29) |
| 2022 - C3+ NGL Swap | 39,564 | Bbls | — | — | — | 50.57 | (3) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2022 - Ethane Swaps | 47,000 | Bbls | — | — | — | 12.81 | | (20) |
| | 5,050,598 | Bbls | | | | | $ | (10,276) |

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and prime rate based, as determined by our lenders, and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on our obligations. As of September 30, 2017, we did not have any interest rate derivatives in place, however we do from time to time enter interest rate derivatives to manage our interest rate exposure. We did not have any interest rate derivatives in place as of December 31, 2016. Based on our total debt as of September 30, 2017, of approximately $814.5 million, a 1.0% change in interest rates would impact our interest expense by approximately $8.1 million.

## Item 4. Controls and Procedures.

### Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that that information we are required to disclose in reports that we file or submit under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. Such controls include those designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”), to allow timely decisions regarding required disclosure.

Our management (with the participation of our CEO and CFO) has evaluated the effectiveness 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 report. Based on this evaluation, our CEO and CFO have concluded that, as of September 30, 2017, our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) were effective to provide reasonable assurance that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

### Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) promulgated under the Exchange Act) during the quarter ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Limitations Inherent in All Controls

Our management, including our CEO and CFO, recognizes that the disclosure controls and procedures and internal controls (discussed above) cannot prevent all errors or all attempts at fraud. Any controls system, no matter how well-crafted and operated, can only provide reasonable, and not absolute, assurance of achieving the desired control objectives. Because of the inherent limitations in any control system, no evaluation or implementation of a control system can provide complete assurance that all control issues and all possible instances of fraud have been, or will be, detected.

## PART II
## OTHER INFORMATION

**Item 1. Legal Proceedings.**

The information set forth under the subsections *Legal Reserves* and *Environmental* in Note 12, *Commitments and Contingencies*, to our Consolidated Financial Statements included in Part I, Item 1 of this Quarterly Report on Form 10-Q is incorporated herein by reference.

**Item 1A. Risk Factors.**

During the quarter ended September 30, 2017, there were no material changes to the risk factors previously reported in our Annual Report on Form 10-K for the year ended December 31, 2016.

**Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.**

None.

**Item 3. Defaults upon Senior Securities.**

None.

**Item 4. Mine Safety Disclosures.**

None.

**Item 5. Other Information.**

None.

**Item 6. Exhibits.**

| Exhibit Number | Exhibit Title |
|---|---|
| 10.1 | Form of Change in Control Agreement as entered into between the Company and each of Messrs. Thomas G. Rajan, Robert W. Ovitz, Curtis J. Walker, David E. Pratt and F. Scott Hodges, effective as of August 11, 2017 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on August 11, 2017). |
| 31.1* | Certification of Chief Executive Officer (Principal Executive Officer) pursuant to Section 302 of the Sarbanes-Oxley Act. |
| 31.2* | Certification of Chief Financial Officer (Principal Financial Officer) pursuant to Section 302 of the Sarbanes-Oxley Act. |
| 32.1* | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act. |
| 32.2* | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act. |
| 101.INS* | XBRL Instance Document |
| 101.SCH* | XBRL Taxonomy Extension Schema Document |
| 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 |

* These exhibits are filed 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.

REX ENERGY CORPORATION
(Registrant)

Date: November 14, 2017

By: /s/ Thomas C. Stabley
Thomas C. Stabley
Chief Executive Officer
(Principal Executive Officer)

Date: November 14, 2017

By: /s/ Thomas Rajan
Thomas Rajan
Chief Financial Officer
(Principal Financial Officer)

**Exhibit 31.1**

**CERTIFICATION**

I, Thomas C. Stabley, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Rex Energy Corporation;

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 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: November 14, 2017

/s/ THOMAS C. STABLEY

**Thomas C. Stabley**
**Chief Executive Officer**
**(Principal Executive Officer)**

**Exhibit 31.2**

**CERTIFICATION**

I, Thomas Rajan, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Rex Energy Corporation;

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 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: November 14, 2017

/s/ THOMAS RAJAN

**Thomas Rajan**
**Chief Financial Officer**
**(Principal Financial Officer)**

**Exhibit 32.1**

**Certification Pursuant to**
**Section 906 of the Sarbanes-Oxley Act of 2002**
**(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)**

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Thomas C. Stabley, Chief Executive Officer of Rex Energy Corporation, a Delaware corporation (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Dated: November 14, 2017

/s/ THOMAS C. STABLEY

**Thomas C. Stabley**
**Chief Executive Officer**
**(Principal Executive Officer)**

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and is not being filed as part of the Report or as a separate disclosure document.

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

**Exhibit 32.2**

**Certification Pursuant to**
**Section 906 of the Sarbanes-Oxley Act of 2002**
**(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)**

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Thomas Rajan, Chief Financial Officer of Rex Energy Corporation, a Delaware corporation (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Dated: November 14, 2017

/s/ THOMAS RAJAN

**Thomas Rajan**
**Chief Financial Officer**
**(Principal Financial Officer)**

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and is not being filed as part of the Report or as a separate disclosure document.

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