QEP RESOURCES, INC.
Form 10-Q
October 25, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2017

o 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: 001-34778
QEP RESOURCES, INC.

(Exact name of registrant as specified in its charter)

STATE OF DELAWARE	87-0287750
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1050 17th Street, Suite 800, Denver, Colorado 80265
(Address of principal executive offices)

Registrant’s telephone number, including area code (303) 672-6900

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 ý No o

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 (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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

Large accelerated filer ý		Accelerated filer	o
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	o

Emerging growth company o

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. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ý

At September 30, 2017, there were 240,935,039 shares of the registrant’s common stock, $0.01 par value, outstanding.

QEP Resources, Inc.
Form 10-Q for the Quarter Ended September 30, 2017

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
REVENUES	(in millions, except per share amounts)			
Oil sales	$218.0	$201.6	$655.7	$553.1
Gas sales	130.7	123.2	399.4	287.5
NGL sales	32.2	19.8	84.0	56.2
Other revenue	3.6	2.5	10.3	4.3
Purchased oil and gas sales	5.6	35.3	44.5	76.3
Total Revenues	390.1	382.4	1,193.9	977.4
OPERATING EXPENSES				
Purchased oil and gas expense	6.9	37.1	45.4	80.8
Lease operating expense	76.2	50.7	215.4	163.3
Transportation and processing costs	60.2	75.8	202.6	218.9
Gathering and other expense	1.7	0.9	5.0	3.8
General and administrative	43.4	66.5	108.3	157.9
Production and property taxes	28.5	26.8	86.1	65.3
Depreciation, depletion and amortization	176.9	217.8	560.2	667.5
Exploration expenses	21.3	0.2	21.7	0.9
Impairment	28.3	5.0	28.4	1,188.2
Total Operating Expenses	443.4	480.8	1,273.1	2,546.6
Net gain (loss) from asset sales	185.4	5.3	205.2	5.0
OPERATING INCOME (LOSS)	132.1	(93.1)	126.0	(1,564.2)
Realized and unrealized gains (losses) on derivative contracts (Note 7)	(104.3)	44.5	163.3	(85.1)
Interest and other income	0.1	4.6	2.5	5.6
Interest expense	(34.4)	(35.9)	(103.1)	(109.2)
INCOME (LOSS) BEFORE INCOME TAXES	(6.5)	(79.9)	188.7	(1,752.9)
Income tax (provision) benefit	3.2	29.0	(69.7)	641.2
NET INCOME (LOSS)	$(3.3)	$(50.9)	$119.0	$(1,111.7)
Earnings (loss) per common share				
Basic	$(0.01)	$(0.21)	$0.49	$(5.15)
Diluted	$(0.01)	$(0.21)	$0.49	$(5.15)
Weighted-average common shares outstanding				
Used in basic calculation	240.7	239.6	240.5	215.7
Used in diluted calculation	240.7	239.6	240.5	215.7
Dividends per common share	$—	$—	$—	$—

See Notes accompanying the Condensed Consolidated Financial Statements.

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QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Net income (loss)	$(3.3)	$(50.9)	$119.0	$(1,111.7)
Other comprehensive income, net of tax:				
Postretirement medical plan change[1]	—	—	1.6	—
Pension and other postretirement plans adjustments:				
Amortization of prior service costs[2]	0.1	0.2	0.4	0.6
Amortization of actuarial losses[3]	0.1	0.2	0.2	0.4
Other comprehensive income	0.2	0.4	2.2	1.0
Comprehensive income (loss)	$(3.1)	$(50.5)	$121.2	$(1,110.7)

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(1) Presented net of income tax expense of $1.0 million during the nine months ended September 30, 2017.

(2) Presented net of income tax expense of $0.1 million and $0.3 million during the three and nine months ended September 30, 2017, respectively. Presented net of income tax expense of $0.1 million and $0.4 million during the three and nine months ended September 30, 2016, respectively.

(3) Presented net of income tax expense of $0.1 million during the nine months ended September 30, 2017. Presented net of income tax expense of $0.1 million and $0.2 million during the three and nine months ended September 30, 2016, respectively.

See Notes accompanying the Condensed Consolidated Financial Statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2017	December 31, 2016
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$782.6	$ 443.8
Accounts receivable, net	120.4	155.7
Income tax receivable	17.9	18.6
Fair value of derivative contracts	3.8	—
Hydrocarbon inventories, at lower of average cost or net realizable value	6.1	10.4
Prepaid expenses and other	10.2	11.6
Total Current Assets	941.0	640.1
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	11,847.2	14,232.5
Unproved properties	703.6	871.5
Gathering and other	311.0	301.8
Materials and supplies	34.6	32.7
Total Property, Plant and Equipment	12,896.4	15,438.5
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	6,492.3	8,797.7
Gathering and other	111.9	101.8
Total Accumulated Depreciation, Depletion and Amortization	6,604.2	8,899.5
Net Property, Plant and Equipment	6,292.2	6,539.0
Fair value of derivative contracts	1.7	—
Other noncurrent assets	112.5	66.3
TOTAL ASSETS	$7,347.4	$ 7,245.4
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$—	$ 12.3
Accounts payable and accrued expenses	388.6	269.7
Production and property taxes	37.4	30.1
Interest payable	32.8	32.9
Fair value of derivative contracts	13.4	169.8
Current portion of long-term debt	134.0	—
Total Current Liabilities	606.2	514.8
Long-term debt	1,890.6	2,020.9
Deferred income taxes	895.7	825.9
Asset retirement obligations	189.3	225.8
Fair value of derivative contracts	2.4	32.0
Other long-term liabilities	125.7	123.3
Commitments and contingencies (Note 9)		
EQUITY		
Common stock – par value $0.01 per share; 500.0 million shares authorized; 242.8 million and 240.7 million shares issued, respectively	2.4	2.4
Treasury stock – 1.9 million and 1.1 million shares, respectively	(33.2)	(22.9)
Additional paid-in capital	1,390.5	1,366.6

Retained earnings	2,292.3	2,173.3
Accumulated other comprehensive income (loss)	(14.5)	(16.7)
Total Common Shareholders' Equity	3,637.5	3,502.7
TOTAL LIABILITIES AND EQUITY	$7,347.4	$ 7,245.4

See Notes accompanying the Condensed Consolidated Financial Statements.

QEP RESOURCES, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
OPERATING ACTIVITIES	(in millions)	
Net income (loss)	$119.0	$(1,111.7)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	560.2	667.5
Deferred income taxes	68.5	(581.1)
Impairment	28.4	1,188.2
Bargain purchase gain from acquisition	0.4	(4.4)
Other non-cash activity	(9.4)	—
Dry hole exploratory well expense	21.2	—
Share-based compensation	13.5	29.0
Amortization of debt issuance costs and discounts	4.8	4.8
Net (gain) loss from asset sales	(205.2)	(5.0)
Unrealized (gains) losses on marketable securities	(2.1)	(1.2)
Unrealized (gains) losses on derivative contracts	(161.6)	218.6
Changes in operating assets and liabilities	44.1	128.2
Net Cash Provided by (Used in) Operating Activities	481.8	532.9
INVESTING ACTIVITIES		
Property acquisitions	(94.5)	(39.9)
Acquisition deposit held in escrow	(36.6)	(30.0)
Property, plant and equipment, including exploratory well expense	(779.6)	(411.2)
Proceeds from disposition of assets	787.9	28.9
Net Cash Provided by (Used in) Investing Activities	(122.8)	(452.2)
FINANCING ACTIVITIES		
Checks outstanding in excess of cash balances	(12.3)	(25.5)
Repayment of senior notes	—	(176.8)
Long-term debt issuance costs paid	(1.1)	—
Proceeds from credit facility	2.0	—
Repayments of credit facility	(2.0)	—
Treasury stock repurchases	(6.8)	(4.1)
Proceeds from issuance of common stock, net	—	781.6
Excess tax (provision) benefit on share-based compensation	—	0.2
Net Cash Provided by (Used in) Financing Activities	(20.2)	575.4
Change in cash and cash equivalents	338.8	656.1
Beginning cash and cash equivalents	443.8	376.1
Ending cash and cash equivalents	$782.6	$1,032.2
Supplemental Disclosures:		
Cash paid for interest, net of capitalized interest	$96.6	$107.0
Cash paid (refund received) for income taxes, net	$0.5	$(123.3)
Non-cash Investing Activities:		
Change in capital expenditure accruals and other non-cash adjustments	$68.0	$(20.4)

See Notes accompanying the Condensed Consolidated Financial Statements.

QEP RESOURCES, INC.
NOTES ACCOMPANYING THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 – Basis of Presentation

Nature of Business

QEP Resources, Inc. is an independent crude oil and natural gas exploration and production company focused in two regions of the United States: the Northern Region (primarily in North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

Basis of Presentation of Interim Condensed Consolidated Financial Statements

The interim Condensed Consolidated Financial Statements contain the accounts of QEP and its majority-owned or controlled subsidiaries. The Condensed Consolidated Financial Statements were prepared in accordance with Generally Accepted Accounting Principles (GAAP) in the United States and with the instructions for Quarterly Reports on Form 10-Q and Regulation S-X. All significant intercompany accounts and transactions have been eliminated in consolidation.

The Condensed Consolidated Financial Statements reflect all normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair statement of financial position and results of operations for the interim periods presented. Interim Condensed Consolidated Financial Statements and the year-end balance sheet do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These Condensed Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements and Notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2016.

The preparation of the Condensed Consolidated Financial Statements and Notes in conformity with GAAP requires that management make estimates and assumptions that affect revenues, expenses, assets and liabilities, and disclosure of contingent assets and liabilities. Actual results could differ from estimates. The results of operations for the three and nine months ended September 30, 2017, are not necessarily indicative of the results that may be expected for the year ending December 31, 2017.

Reclassifications

Certain prior period balances on the Condensed Consolidated Statement of Operations have been reclassified to conform to the current year presentation. Such reclassifications had no effect on the Company's net income, earnings per share, cash flows or retained earnings previously reported.

Impairment of Long-Lived Assets

During the nine months ended September 30, 2017, QEP recorded impairment charges of $28.4 million, which was primarily related to unproved leasehold acreage in the Central Basin Platform. Refer to Note 4 – Capitalized Exploratory Well Costs for more information.

During the nine months ended September 30, 2016, QEP recorded impairment charges of $1,188.2 million, of which $1,167.9 million was related to proved properties due to lower future oil and gas prices, $16.6 million was related to expiring leaseholds on unproved properties and $3.7 million was related to an impairment of goodwill. Of the $1,167.9 million impairment on proved properties, $1,164.0 million related to Pinedale properties, $3.5 million related to Other Northern properties and $0.4 million related to Other Southern properties.

Income Taxes

During the three months ended September 30, 2017, QEP's combined effective federal and state income tax rate was 49.2%. The effective rate is higher than the combined federal and state statutory rate primarily due to a year-to-date adjustment to the tax provision for a permanent adjustment related to marginal well tax credits as well as a change in income between states.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which seeks to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In addition, new and enhanced disclosures will be required. The amendment is effective prospectively for reporting periods beginning on or after December 15, 2017, and early adoption is permitted for periods beginning on or after December 15, 2016. The two permitted transition methods under the new standard are the full retrospective method, in which case the standard would be applied to each prior reporting period presented, or the modified retrospective method, in which case the cumulative effect of applying the standard would be recognized at the date of initial application. The Company does not expect net income (loss) or cash flows to be materially impacted by the new standard, however, the Company is currently analyzing whether changes to total revenues and total expenses will be necessary to properly reflect revenue for certain pipeline gathering, transportation and gas processing agreements. The Company continues to evaluate the expected disclosure requirements, changes to relevant business practices, accounting policies and control activities as a result of the adoption of the ASU and has not yet developed estimates of the quantitative impact to the Company's Condensed Consolidated Financial Statements. The Company has selected the modified retrospective method and will adopt this guidance on the effective date of January 1, 2018.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which requires lessees to recognize the lease assets and lease liabilities classified as operating leases on the balance sheet and disclose key quantitative and qualitative information about leasing arrangements. The amendment will be effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's Condensed Consolidated Financial Statements.

In March 2016, the FASB issued ASU No. 2016-06, Derivatives and hedging (Topic 815): Contingent put and call options in debt instruments, which clarifies the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The amendment was effective prospectively for reporting periods beginning on or after December 15, 2016, and early adoption was permitted. The Company adopted this standard in the first quarter of 2017 and the adoption of this new standard did not have a material impact on the Company's Condensed Consolidated Financial Statements.

In March 2016, the FASB issued ASU No. 2016-09, Compensation – Stock Compensation (Topic 718): Improvements to employee share-based payment accounting, which includes provisions intended to simplify various aspects related to how share-based compensation payments are accounted for and presented in the financial statements. This amendment was effective prospectively for reporting periods beginning after December 15, 2016, and early adoption was permitted. The Company adopted this standard in the first quarter of 2017 and the adoption of this new standard did not have a material impact on the Company's Condensed Consolidated Financial Statements.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the definition of a business, which clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of businesses. The amendment will be effective prospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's Condensed Consolidated Financial Statements.

In January 2017, the FASB issued ASU No. 2017-04, Intangibles – Goodwill and Other (Topic 350): Simplifying the test for goodwill impairment, which eliminates the requirement to calculate implied fair value of goodwill to measure the goodwill impairment charge. The amendment will be effective prospectively for reporting periods beginning after December 15, 2019, and early adoption is permitted. The Company early adopted this standard in the first quarter of 2017 and the adoption of this new standard did not have a material impact on the Company's Condensed Consolidated Financial Statements.

In March 2017, the FASB issued ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, which changes how employers of a defined benefit plan present net periodic benefit cost in the statement of operations. The amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company early adopted this standard in the first quarter of 2017 and the adoption of this new standard did not have a material impact on the Company's Condensed Consolidated Financial Statements. See Note 11 – Employee Benefits for additional information regarding the Company's pension and other postretirement plans.

Note 2 – Acquisitions and Divestitures

2016 Permian Basin Acquisition

In October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $591.0 million, subject to customary post-closing purchase price adjustments (the 2016 Permian Basin Acquisition). The 2016 Permian Basin Acquisition consisted of approximately 9,600 net acres in Martin County, Texas, which are primarily held by production from existing vertical wells. The 2016 Permian Basin Acquisition was funded with cash on hand, which included proceeds from an equity offering in June 2016.

The 2016 Permian Basin Acquisition meets the definition of a business combination under ASC 805, Business Combinations, as it includes significant proved properties. QEP allocated the cost of the 2016 Permian Basin Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $18.8 million and $38.6 million and net income of $3.5 million and $5.4 million were generated from the acquired properties during the three and nine months ended September 30, 2017, respectively, and are included in QEP's Condensed Consolidated Statements of Operations. In conjunction with the 2016 Permian Basin Acquisition, the Company recorded an $18.2 million bargain purchase gain in 2016. The acquisition resulted in a bargain purchase gain primarily as a result of an increase in future oil prices from the execution of the purchase and sale agreement to the closing date of the acquisition. During the nine months ended September 30, 2017, the Company reduced the bargain purchase gain by $0.4 million due to purchase price adjustments. The bargain purchase gain is reported on the Condensed Consolidated Statements of Operations within "Interest and other income (expense)".

The following table presents a summary of the Company's purchase accounting entries (in millions) as of September 30, 2017:

Consideration:	
Total consideration	$591.0
Amounts recognized for fair value of assets acquired and liabilities assumed:	
Proved properties	$406.2
Unproved properties	214.2
Asset retirement obligations	(11.6)
Bargain purchase gain	(17.8)
Total fair value	$591.0

The following unaudited, pro forma results of operations are provided for the three and nine months ended September 30, 2016. Pro forma results are not provided for the three and nine months ended September 30, 2017, because the 2016 Permian Basin Acquisition occurred during the fourth quarter of 2016, and therefore, the results are included in QEP's results of operations for the three and nine months ended September 30, 2017. These supplemental pro forma results of operations are provided for illustrative purposes only and may not be indicative of the actual results that would have been achieved by the acquired properties for the periods presented, or that may be achieved by such properties in the future. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors. The pro forma information is based on QEP's condensed consolidated results of operations for the three and nine months ended September 30, 2016, the acquired properties' historical results of operations and estimates of the effect of the transaction on the combined results. The pro forma results of operations have been prepared by adjusting and quantifying the historical results of QEP to include the historical results of the acquired properties based on information provided by the seller and the impact of the preliminary purchase price allocation. The pro forma results of operations do not include any cost savings or other synergies that may result from the 2016 Permian Basin Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired properties.

	Three Months Ended		Nine Months Ended	
	September 30, 2016		September 30, 2016	
	Actual	Pro forma	Actual	Pro forma
	(in millions, except per share amounts)			
Revenues	$382.4	$387.3	$977.4	$991.9
Net income (loss)	$(50.9)	$(51.3)	$(1,111.7)	$(1,113.4)
Earnings (loss) per common share				
Basic	$(0.21)	$(0.21)	$(5.15)	$(5.16)
Diluted	$(0.21)	$(0.21)	$(5.15)	$(5.16)

Other Acquisitions

During the nine months ended September 30, 2017, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage and additional surface acreage in the Permian Basin, for an aggregate purchase price of $94.5 million. In conjunction with these acquisitions, the Company recorded $5.3 million of goodwill. The goodwill is reported on the Condensed Consolidated Balance Sheets within "Other noncurrent assets".

During the nine months ended September 30, 2016, QEP acquired various oil and gas properties, which primarily included additional interests in QEP's operated wells and additional undeveloped leasehold acreage in the Permian and Williston basins, for an aggregate purchase price of $46.1 million, of which $39.9 million was cash and $6.2 million was non-cash related to the settlement of an accounts receivable balance. In conjunction with these acquisitions, the Company recorded $3.7 million of goodwill, which was subsequently impaired in 2016, and a $4.4 million bargain purchase gain. The bargain purchase gain is reported on the Condensed Consolidated Statement of Operations within "Interest and other income (expense)".

Pinedale Divestiture

In September 2017, QEP closed on its previously announced divestiture of its assets in Pinedale (the Pinedale Divestiture), for net cash proceeds (after purchase price adjustments) of $718.2 million, subject to post-closing purchase price adjustments, and recorded a pre-tax gain on sale of $178.8 million which was recorded within "Net gain (loss) from asset sales" on the Condensed Consolidated Statements of Operations. As part of the purchase and sale agreement, at the request of the buyer, QEP agreed to enter into derivative contracts covering a portion of Pinedale's future production. Those derivative contracts were novated to the buyer at closing. In addition, QEP agreed to reimburse the buyer for certain deficiency charges it incurs related to gas processing and NGL transportation and fractionation contracts, if any, between the effective date of the sale and December 31, 2019, in an aggregate amount not to exceed $45.0 million. The fair value of the deficiency charges was measured utilizing an internally developed cash flow model discounted at QEP's weighted average cost of debt. Given the unobservable nature of the inputs, the fair value calculation associated with the deficiency charges is considered Level 3 within the fair value hierarchy. As of September 30, 2017, the liability associated with estimated future payments for this commitment was $35.0 million, of which $28.0 million is reported on the Condensed Consolidated Balance Sheets within "Accounts payable and accrued expenses" and $7.0 million is reported on the Condensed Consolidated Balance Sheets within "Other long-term liabilities".

QEP accounted for revenues and expenses related to Pinedale, including the pre-tax gain on sale of $178.8 million, during the three and nine months ended September 30, 2017 and 2016, as income from continuing operations on the

Condensed Consolidated Statements of Operations because the sale of the Pinedale assets did not cause a strategic shift for the Company and as a result, did not qualify as discontinued operations under ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The Pinedale Divestiture did, however, represent the sale of an individually significant component. For the three and nine months ended September 30, 2017, QEP recorded net income before income taxes related to Pinedale, prior to the divestiture, of $208.2 million and $251.2 million, respectively, which both include the pre-tax gain on sale of $178.8 million. For the three and nine months ended September 30, 2016, QEP recorded net income before income taxes related to Pinedale of $19.2 million and a net loss before income taxes of $1,177.0 million, respectively. The net loss before income taxes was primarily due to an impairment on proved properties of $1,164.0 million recognized in 2016 as a result of a decrease in expected future gas prices.

As a part of the Pinedale Divestiture, QEP expects to incur restructuring costs of approximately $0.8 million, of which approximately $0.5 million is related to one-time termination benefits and approximately $0.3 million is related to the relocation of certain employees. During the three and nine months ended September 30, 2017, restructuring costs of $0.5 million were incurred related to the Pinedale Divestiture, all of which were related to one-time termination benefits and will be paid in the fourth quarter of 2017. The Company expects to incur an additional $0.3 million of restructuring costs related to the relocation of certain employees within the next twelve months. These restructuring costs were recorded within "Net gain (loss) from asset sales" on the Condensed Consolidated Statement of Operations.

Other Divestitures

In addition to the Pinedale Divestiture, during the nine months ended September 30, 2017, QEP received proceeds of $69.7 million and recorded a pre-tax gain on sale of $26.4 million, primarily related to the divestiture of certain non-core properties in the Other Northern area.

During the nine months ended September 30, 2016, QEP received proceeds of $28.9 million and recorded a pre-tax gain on sale of $5.0 million, primarily related to the divestiture of certain non-core properties in the Other Southern area.

The gains and losses were recorded within "Net gain (loss) from asset sales" on the Condensed Consolidated Statements of Operations.

Note 3 – Earnings Per Share

Basic earnings per share (EPS) are computed by dividing net income by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options. QEP’s unvested restricted share awards are included in weighted-average basic common shares outstanding because, once the shares are granted, the restricted share awards are considered issued and outstanding, the historical forfeiture rate is minimal and the restricted share awards are eligible to receive dividends.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings per share pursuant to the two-class method. The Company’s unvested restricted share awards contain non-forfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company’s unvested restricted share awards do not have a contractual obligation to share in losses of the Company. The Company’s unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings per common share. During the three and nine months ended September 30, 2017, there were no anti-dilutive shares. During the three and nine months ended September 30, 2016, there were anti-dilutive shares of 0.2 million and 0.1 million, respectively, not included in diluted common shares outstanding as they were anti-dilutive to QEP's net loss.

The following is a reconciliation of the components of basic and diluted shares used in the EPS calculation:

	Three Months Ended	Nine Months Ended

	September 30,		September 30,	
	2017	2016	2017	2016
	(in millions)			
Weighted-average basic common shares outstanding	240.7	239.6	240.5	215.7
Potential number of shares issuable upon exercise of in-the-money stock options under the Long-Term Stock Incentive Plan	—	—	—	—
Average diluted common shares outstanding	240.7	239.6	240.5	215.7

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Note 4 – Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below.

	Capitalized Exploratory Well Costs 2017 (in millions)
Balance at January 1,	$ 14.2
Additions to capitalized exploratory well costs	10.6
Reclassifications to proved properties	(3.6)
Capitalized exploratory well costs charged to expense	(21.2)
Balance at September 30,	$ —

Central Basin Platform exploration project. During the nine months ended September 30, 2017, QEP's exploratory well activity was related to the Central Basin Platform exploration project in the Permian Basin targeting the Woodford Formation. QEP completed a second exploratory well related to this project in the first half of 2017. During the three months ended September 30, 2017, based on the performance of the two exploratory wells that were drilled and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project and would seek to monetize the assets. QEP charged $21.2 million of exploratory well costs to exploration expense. In conjunction with the expensing of the exploratory well costs, QEP charged $28.3 million of the associated unproved leasehold acreage in the Central Basin Platform to impairment expense during the three months ended September 30, 2017. QEP wrote down the Central Basin Platform assets to their fair market value of $3.6 million and reclassified the assets to proved properties.

Note 5 – Asset Retirement Obligations

QEP records asset retirement obligations (ARO) associated with the retirement of tangible, long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. Revisions to the ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Of the $194.2 million and $231.6 million ARO liability for the periods ended September 30, 2017 and December 31, 2016, respectively, $4.9 million and $5.8 million, respectively, were included as a liability within "Accounts payable and accrued expenses" on the Condensed Consolidated Balance Sheets.

The following is a reconciliation of the changes in the Company's ARO for the period specified below:

	Asset Retirement Obligations 2017 (in millions)
ARO liability at January 1,	$ 231.6
Accretion	6.0
Additions	6.2
Revisions	0.2

Liabilities related to assets sold[(1)]	(40.8)
Liabilities settled	(9.0)
ARO liability at September 30,	$ 194.2

(1) Liabilities related to assets sold for the nine months ended September 30, 2017, includes $34.9 million related to the Pinedale Divestiture (refer to Note 2 – Acquisitions and Divestitures for more information).

Note 6 – Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820, Fair Value Measurements and Disclosures. This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair value measurements. ASC 820 also establishes a fair value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability.

QEP has determined that its commodity derivative instruments are Level 2. The Level 2 fair value of commodity derivative contracts (see Note 7 – Derivative Contracts) is based on market prices posted on the respective commodity exchange on the last trading day of the reporting period and industry standard discounted cash flow models. QEP primarily applies the market approach for recurring fair value measurements and maximizes its use of observable inputs and minimizes its use of unobservable inputs. QEP considers bid and ask prices for valuing the majority of its assets and liabilities measured and reported at fair value. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company's policy is to recognize significant transfers between levels at the end of the reporting period.

Certain of the Company's commodity derivative instruments are valued using industry standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable prices at which transactions are executed in the marketplace. The determination of fair value for derivative assets and liabilities also incorporates nonperformance risk for counterparties and for QEP. Derivative contract fair values are reported on a net basis to the extent a legal right of offset with the counterparty exists.

The fair value of financial assets and liabilities at September 30, 2017 and December 31, 2016, is shown in the table below:

	Fair Value Measurements Gross Amounts of Assets and Liabilities Level 1	Level 2	Level 3	Netting Adjustments[(1)]	Net Amounts Presented on the Condensed Consolidated Balance Sheets
	September 30, 2017				
Financial Assets	(in millions)				
Fair value of derivative contracts – short-term	$ —	$ 6.9	$ —	$ (3.1)	$ 3.8
Fair value of derivative contracts – long-term	—	2.5	—	(0.8)	1.7
Total financial assets	$ —	$ 9.4	$ —	$ (3.9)	$ 5.5
Financial Liabilities					
Fair value of derivative contracts – short-term	$ —	$ 16.5	$ —	$ (3.1)	$ 13.4
Fair value of derivative contracts – long-term	—	3.2	—	(0.8)	2.4
Total financial liabilities	$ —	$ 19.7	$ —	$ (3.9)	$ 15.8
	December 31, 2016				
Financial Assets					
Fair value of derivative contracts – short-term	$ —	$ —	$ —	$ —	$ —
Fair value of derivative contracts – long-term	—	—	—	—	—
Total financial assets	$ —	$ —	$ —	$ —	$ —
Financial Liabilities					
Fair value of derivative contracts – short-term	$ —	$ 169.8	$ —	$ —	$ 169.8
Fair value of derivative contracts – long-term	—	32.0	—	—	32.0
Total financial liabilities	$ —	$ 201.8	$ —	$ —	$ 201.8

(1) The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the Condensed Consolidated Balance Sheets, for the contracts that contain netting provisions. See Note 7 – Derivative Contracts for additional information regarding the Company's derivative contracts.

The following table discloses the fair value and related carrying amount of certain financial instruments not disclosed in other Notes to the Condensed Consolidated Financial Statements in this Quarterly Report on Form 10-Q:

	Carrying Amount	Level 1 Fair Value	Carrying Amount	Level 1 Fair Value
	September 30, 2017		December 31, 2016	
Financial Assets	(in millions)			
Cash and cash equivalents	$782.6	$782.6	$443.8	$443.8
Financial Liabilities				
Checks outstanding in excess of cash balances	$—	$—	$12.3	$12.3

Long-term debt	$2,024.6	$2,062.1	$2,020.9	$2,104.3

The carrying amounts of cash and cash equivalents and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the quarter.

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and is based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO includes plugging costs and reserve lives. A reconciliation of the Company’s ARO is presented in Note 5 – Asset Retirement Obligations.

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring measurements. The Company utilizes fair value on a periodic basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. During the nine months ended September 30, 2017, the Company recorded no impairments on proved oil and gas properties. During the nine months ended September 30, 2016, the Company recorded impairments on certain proved oil and gas properties of $1,167.9 million resulting in a reduction of the associated carrying value to fair value. The fair value of the property was measured utilizing the income approach and utilizing inputs that are primarily based upon internally developed cash flow models discounted at an appropriate weighted average cost of capital. Given the unobservable nature of the inputs, fair value calculations associated with proved oil and gas property impairments are considered Level 3 within the fair value hierarchy.

Acquisitions of proved and unproved properties are also measured at fair value on a nonrecurring basis. The Company utilizes a discounted cash flow model to estimate the fair value of acquired property as of the acquisition date which utilizes the following inputs to estimate future net cash flows: (i) estimated quantities of oil, gas and NGL reserves; (ii) estimates of future commodity prices; and (iii) estimated production rates, future operating and development costs, which are based on the Company's historic experience with similar properties. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage. Due to the unobservable characteristics of the inputs, the fair value of the acquired properties is considered Level 3 within the fair value hierarchy. See Note 2 – Acquisitions and Divestitures for additional information on the fair value of acquired properties.

Note 7 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity price derivative instruments to reduce the impact of potential downward movements in commodity prices on cash flow, returns on capital investment, and other financial results. However, these instruments typically limit gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production, but generally, QEP enters into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. In addition, QEP may enter into commodity derivative contracts on a portion of its storage transactions. QEP does not enter into commodity derivative contracts for speculative purposes.

QEP uses commodity derivative instruments known as fixed-price swaps or collars to realize a known price or price range for a specific volume of production delivered into a regional sales point. QEP's commodity derivative instruments do not require the physical delivery of oil or gas between the parties at settlement. All transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps based at Cushing, Oklahoma or oil price swaps that use Intercontinental Exchange, Inc. (ICE) Brent oil prices as the reference price. Gas price derivative instruments are typically structured as fixed-price swaps or collars at NYMEX Henry Hub or regional price indices. QEP also enters into oil and gas basis swaps to achieve a fixed-price swap for a portion of its oil and gas sales at prices that reference specific regional index prices.

QEP does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates. QEP's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings. QEP routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings and avoiding the concentration of credit exposure by transacting with multiple counterparties. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

Derivative Contracts – Production

The following table presents QEP’s volumes and average prices for its commodity derivative swap contracts as of September 30, 2017:

Year	Index	Total Volumes	Average Swap Price per Unit
		(in millions)	
Oil sales		(bbls)	($/bbl)
2017	NYMEX WTI	3.6	$ 51.51
2018	NYMEX WTI	14.6	$ 52.42
2019	NYMEX WTI	3.7	$ 50.30
Gas sales		(MMBtu)	($/MMBtu)
2017	NYMEX HH	24.8	$ 2.87
2017	IFNPCR	6.4	$ 2.49
2018	NYMEX HH	105.9	$ 2.99
2019	NYMEX HH	14.6	$ 2.87

The following table presents QEP's volumes and average prices for its commodity derivative gas collars as of September 30, 2017:

Year	Index	Total Volumes	Average Price Floor	Average Price Ceiling
		(in millions)		
		(MMBtu)	($/MMBtu)	($/MMBtu)
2017	NYMEX HH	2.8	$ 2.50	$ 3.50

QEP uses oil and gas basis swaps, combined with NYMEX WTI and NYMEX HH fixed price swaps, to achieve fixed price swaps for the location at which it sells its physical production. The following table presents details of QEP's oil and gas basis swaps as of September 30, 2017:

Year	Index Less Differential	Index	Total Volumes	Weighted-Average Differential
			(in millions)	
Oil sales			(bbls)	($/bbl)
2017	NYMEX WTI	Argus WTI Midland	1.1	$ (0.67)
2018 (Full Year)	NYMEX WTI	Argus WTI Midland	7.3	$ (1.06)
2018 (July through December)	NYMEX WTI	Argus WTI Midland	0.6	$ (0.81)
2019	NYMEX WTI	Argus WTI Midland	2.2	$ (0.98)
Gas sales			(MMBtu)	($/MMBtu)
2018	NYMEX HH	IFNPCR	7.3	$ (0.16)

Derivative Contracts – Gas Storage

QEP enters into commodity derivative transactions to lock in a margin on gas volumes placed into storage. The following table presents QEP's volumes and average prices for its storage commodity derivative swap contracts as of September 30, 2017:

Year	Type of Contract	Index	Total Volumes	Average Swap Price per Unit
			(in millions)	
Gas sales			(MMBtu)	($/MMBtu)
2017	SWAP	IFNPCR	1.5	$ 2.88
2018	SWAP	IFNPCR	0.4	$ 3.05
Gas purchases			(MMBtu)	($/MMBtu)
2017	SWAP	IFNPCR	1.1	$ 2.68

QEP Derivative Financial Statement Presentation

The following table identifies the Condensed Consolidated Balance Sheet location of QEP's outstanding derivative contracts on a gross contract basis as opposed to the net contract basis presentation on the Condensed Consolidated Balance Sheets and the related fair values at the balance sheet dates:

	Balance Sheet line item	Gross asset derivative instruments fair value		Gross liability derivative instruments fair value	
		September 30, 2017	December 31, 2016	September 30, 2017	December 31, 2016
Current:		(in millions)			
Commodity	Fair value of derivative contracts	$6.9	$ —	$16.5	$ 169.8
Long-term:					
Commodity	Fair value of derivative contracts	2.5	—	3.2	32.0
Total derivative instruments		$9.4	$ —	$19.7	$ 201.8

The effects of the change in fair value and settlement of QEP's derivative contracts recorded in "Realized and unrealized gains (losses) on derivative contracts" on the Condensed Consolidated Statements of Operations are summarized in the following table:

Derivative contracts not designated as cash flow hedges	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Realized gains (losses) on commodity derivative contracts	(in millions)			
Production				
Oil derivative contracts	$12.1	$19.1	$21.6	$79.8
Gas derivative contracts	(0.4)	0.4	(19.7)	50.8
Gas Storage				
Gas derivative contracts	—	0.1	(0.2)	2.9
Realized gains (losses) on commodity derivative contracts	11.7	19.6	1.7	133.5
Unrealized gains (losses) on commodity derivative contracts				
Production				
Oil derivative contracts	(86.1)	(0.3)	88.7	(135.9)
Gas derivative contracts	—	24.8	100.5	(80.0)
Gas Storage				
Gas derivative contracts	—	0.4	2.3	(2.7)
Unrealized gains (losses) on commodity derivative contracts	(86.1)	24.9	191.5	(218.6)
Total realized and unrealized gains (losses) on commodity derivative contracts related to production and storage contracts	$(74.4)	$44.5	$193.2	$(85.1)
Derivatives associated with the Pinedale Divestiture[(1)]				
Unrealized gains (losses) on commodity derivative contracts				
Production				
Oil derivative contracts	$(1.3)	$—	$(1.3)	$—
Gas derivative contracts	(23.5)	—	(23.5)	—
NGL derivative contracts	(5.1)	—	(5.1)	—
Unrealized gains (losses) on commodity derivative contracts related to the Pinedale Divestiture	$(29.9)	$—	$(29.9)	$—
Total realized and unrealized gains (losses) on commodity derivative contracts	$(104.3)	$44.5	$163.3	$(85.1)

(1) The unrealized gains (losses) on commodity derivative contracts related to the Pinedale Divestiture are comprised of derivatives entered into in conjunction with the execution of the Pinedale purchase and sale agreement, which were subsequently novated to the buyer upon the closing of the sale in September 2017. Refer to Note 2 – Acquisitions and Divestitures for more information. The unrealized gains (losses) on commodity derivatives associated with the Pinedale Divestiture are offset by an equal amount recorded within "Net gain (loss) from asset sales" on the Condensed Consolidated Statements of Operations.

Note 8 – Debt

As of the indicated dates, the principal amount of QEP's debt consisted of the following:

	September 30, 2017	December 31, 2016
	(in millions)	
Revolving Credit Facility due 2019	$—	$ —
6.80% Senior Notes due 2018	134.0	134.0
6.80% Senior Notes due 2020	136.0	136.0
6.875% Senior Notes due 2021	625.0	625.0
5.375% Senior Notes due 2022	500.0	500.0
5.25% Senior Notes due 2023	650.0	650.0
Less: unamortized discount and unamortized debt issuance costs	(20.4)	(24.1)
Total principal amount of debt (including current portion)	2,024.6	2,020.9
Less: current portion of long-term debt	(134.0)	—
Total long-term debt outstanding	$1,890.6	$ 2,020.9

Of the total debt outstanding on September 30, 2017, the 6.80% Senior Notes due April 1, 2018, the 6.80% Senior Notes due March 1, 2020 and the 6.875% Senior Notes due March 1, 2021, will mature within the next five years. In addition, the revolving credit facility matures on December 2, 2019.

Credit Facility

QEP's revolving credit facility, which matures in December 2019, provides for loan commitments of $1.8 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%; (ii) a leverage ratio under which net funded debt may not exceed 4.25 times consolidated EBITDA (as defined in the credit agreement) for the fiscal quarters ending on and prior to December 31, 2017, 4.00 times for the quarters in fiscal year 2018, and 3.75 times thereafter and (iii) during a ratings trigger period, a present value coverage ratio which requires that the present value of the Company's proved reserves must exceed net funded debt by 1.25 times at any time prior to January 1, 2018, and 1.50 times at any time on or after January 1, 2018. The Company is currently not subject to the present value coverage ratio. At September 30, 2017 and December 31, 2016, QEP was in compliance with the covenants under the credit agreement.

As of September 30, 2017 and December 31, 2016, QEP had no borrowings outstanding under the credit facility and had $1.0 million and $2.8 million, respectively, in letters of credit outstanding under the credit facility.

Senior Notes

As of September 30, 2017, the Company had $2,045.0 million principal amount of senior notes outstanding with maturities ranging from April 2018 to May 2023 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing QEP's senior notes contain customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 9 – Commitments and Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its Condensed Consolidated Financial Statements. In accordance with ASC 450, Contingencies, an accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes.

Legal proceedings are inherently unpredictable and unfavorable resolutions can occur. Assessing contingencies is highly subjective and requires judgment about uncertain future events. When evaluating contingencies related to legal proceedings, the Company may be unable to estimate losses due to a number of factors, including potential defenses, the procedural status of the matter in question, the presence of complex legal and/or factual issues, the ongoing discovery and/or development of information important to the matter.

EPA Request for Information – In July 2015, QEP received an information request from the Environmental Protection Agency (EPA) pursuant to Section 114(a) of the Clean Air Act. The information request sought facts and data about certain tank batteries in QEP's Williston Basin operations. QEP timely responded to the information requests. In August 2016, the EPA requested a conference to review this matter; this conference has been scheduled for November 2017. While no formal federal enforcement action has been commenced in connection with the tank batteries to date, QEP anticipates that resolution of this matter will likely result in monetary penalties and require QEP to incur additional capital expenditures to correct noncompliance issues. We cannot reasonably estimate the loss or range of losses at this preliminary stage.

Note 10 – Share-Based Compensation

QEP issues stock options, restricted share awards and restricted share units under its Long-Term Stock Incentive Plan (LTSIP) and awards performance share units under its Cash Incentive Plan (CIP) to certain officers, employees and non-employee directors. QEP recognizes the expense over the vesting periods for the stock options, restricted share awards, restricted share units and performance share units. There were 5.1 million shares available for future grants under the LTSIP at September 30, 2017.

Share-based compensation expense is recognized within "General and administrative" expense on the Condensed Consolidated Statements of Operations and is summarized in the table below:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
	(in millions)			
Stock options	$0.5	$0.6	$1.7	$1.8
Restricted share awards	5.4	6.0	18.7	18.2
Performance share units	(0.1)	3.2	(6.9)	8.8
Restricted share units	—	0.1	—	0.2
Total share-based compensation expense	$5.8	$9.9	$13.5	$29.0

Stock Options
QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock option awards at the date of grant. Fair value calculations rely upon subjective assumptions used in the mathematical model and may not be representative of future results. The Black-Scholes-Merton model is intended for calculating the value of options not traded on an exchange. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. QEP uses a historical volatility method to estimate the fair value of stock options awards and the risk-free interest rate is based on the yield on U.S. Treasury strips with maturities similar to those of the expected term of the stock options. The stock options typically vest in equal installments over a three-year period from the grant date and

are exercisable immediately upon vesting through the seventh anniversary of the grant date. To fulfill options exercised, QEP either reissues treasury stock or issues new shares.

The calculated fair value of stock options granted and major assumptions used in the model at the date of grant are listed below for the nine months ended September 30, 2017:

	Stock Option Assumptions	
Weighted-average grant date fair value of awards granted during the period	$ 6.44	
Weighted-average risk-free interest rate	1.81	%
Weighted-average expected price volatility	43.9	%
Expected dividend yield	—	%
Expected term in years at the date of grant	4.5	

Stock option transactions under the terms of the LTSIP are summarized below:

	Options Outstanding		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
			(per share)	(in years)	(in millions)
Outstanding at December 31, 2016	2,151,957		$ 25.26		
Granted	418,752		16.77		
Forfeited	(14,172	)	15.33		
Canceled	(202,260	)	27.55		
Outstanding at September 30, 2017	2,354,277		$ 23.62	3.75	$ —
Options Exercisable at September 30, 2017	1,551,861		$ 27.90	2.73	$ —
Unvested Options at September 30, 2017	802,416		$ 15.33	5.73	$ —

During the nine months ended September 30, 2017 and 2016, there were no exercises of stock options. As of September 30, 2017, $2.1 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 2.23 years.

Restricted Share Awards

Restricted share award grants typically vest in equal installments over a three-year period from the grant date. The grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date. The total fair value of restricted share awards that vested during the nine months ended September 30, 2017 and 2016 was $22.9 million and $24.2 million, respectively. The weighted-average grant date fair value of restricted share awards was $14.13 per share and $10.37 per share for the nine months ended September 30, 2017 and 2016, respectively. As of September 30, 2017, $25.2 million of unrecognized compensation cost related to restricted share awards granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 2.17 years.

Transactions involving restricted share awards under the terms of the LTSIP are summarized below:

	Restricted Share Awards Outstanding		Weighted-Average Grant Date Fair Value
			(per share)
Unvested balance at December 31, 2016	3,208,503		$ 14.32
Granted	2,123,016		14.13
Vested	(1,384,011	)	16.54

Forfeited	(240,732)	14.71
Unvested balance at September 30, 2017	3,706,776	$ 13.35

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Performance Share Units

The payouts for performance share units are dependent upon the Company’s total shareholder return compared to a group of its peers over a three-year period. The awards are denominated in share units and have historically been delivered in cash. Beginning with awards granted in 2015, the Company has the option to settle earned awards in cash or shares of common stock under the Company's LTSIP; however, as of September 30, 2017, the Company expects to settle all awards in cash. These awards are classified as liabilities and are included within "Other long-term liabilities" on the Condensed Consolidated Balance Sheets. As these awards are dependent upon the Company's total shareholder return and stock price, they are remeasured at fair value at the end of each reporting period. The weighted-average grant date fair value of the performance share units was $16.90 per share and $10.16 per share for the nine months ended September 30, 2017 and 2016, respectively. As of September 30, 2017, $0.2 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of performance shares granted, is expected to be recognized over a weighted-average vesting period of 2.03 years.

Transactions involving performance share units under the terms of the CIP are summarized below:

	Performance Share Units Outstanding	Weighted-Average Grant Date Fair Value (per share)
Unvested balance at December 31, 2016	1,027,280	$ 17.24
Granted	405,014	16.90
Vested and Paid	(215,439)	31.63
Forfeited	(17,519)	13.88
Unvested balance at September 30, 2017	1,199,336	$ 14.59

Restricted Share Units

Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified, unfunded deferred compensation plan at the time of vesting. These awards are ultimately delivered in cash. They are classified as liabilities and are included in "Other long-term liabilities" on the Condensed Consolidated Balance Sheets and are measured at fair value at the end of each reporting period. The weighted-average grant date fair value of the restricted share units was $16.98 and $10.12 per share for the nine months ended September 30, 2017 and 2016, respectively. As of September 30, 2017, $0.1 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of restricted share units granted, is expected to be recognized over a weighted-average vesting period of 1.43 years.

Transactions involving restricted share units under the terms of the LTSIP are summarized below:

	Restricted Share Units Outstanding	Weighted-Average Grant Date Fair Value (per share)
Unvested balance at December 31, 2016	18,034	$ 10.12
Granted	9,924	16.98
Vested	(6,012)	10.12
Unvested balance at September 30, 2017	21,946	$ 13.22

Note 11 – Employee Benefits

Pension and Other Postretirement Benefits

The Company provides pension and other postretirement benefits to certain employees through three retirement benefit plans: the QEP Resources, Inc. Retirement Plan (the Pension Plan), the Supplemental Executive Retirement Plan (the SERP), and a postretirement medical plan (the Medical Plan).

The Pension Plan is a closed, qualified, defined-benefit pension plan that is funded and provides pension benefits to certain QEP employees. During the nine months ended September 30, 2017, the Company made contributions of $4.0 million to the Pension Plan and does not expect to make additional contributions to the Pension Plan during the remainder of 2017. Contributions to the Pension Plan increase plan assets. The Pension Plan was amended in June 2015 and was frozen effective January 1, 2016, such that employees do not earn additional defined benefits for future services.

The SERP is a nonqualified retirement plan that is unfunded and provides pension benefits to certain QEP employees. During the nine months ended September 30, 2017, the Company made contributions of $1.9 million to its SERP and expects to contribute an additional $0.1 million to its SERP during the remainder of 2017. Contributions to the SERP are used to fund current benefit payments. The SERP was amended and restated in June 2015 and was closed to new participants effective January 1, 2016.

During the nine months ended September 30, 2017, the Company recognized a $0.7 million loss on curtailment related to the SERP in connection with the Pinedale Divestiture, which was recorded on the Condensed Consolidated Statements of Operations within "Net gain (loss) from asset sales".

The Medical Plan is unfunded and provides other postretirement benefits including certain health care and life insurance benefits for certain retired QEP employees. During the nine months ended September 30, 2017, the Company made contributions of $0.2 million to its Medical Plan and expects to contribute an additional $0.1 million to its Medical Plan during the remainder of 2017. Contributions to the Medical Plan are used to fund current benefit payments.

In February 2017, the Company changed the eligibility requirements for active employees eligible for the Medical Plan, as well as retirees currently enrolled. Effective July 1, 2017, the Company no longer offers the Medical Plan to retirees and/or spouses that are Medicare eligible. In addition, the Company no longer offers life insurance to individuals retiring on or after July 1, 2017.

In accordance with the adoption of ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, the Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Condensed Consolidated Statements of Operations. All other expenses related to the Pension Plan, SERP and Medical Plan are recognized within "Interest and other income (expense)" on the Condensed Consolidated Statements of Operations.

The following table sets forth the Company's net periodic benefit costs related to its Pension Plan, SERP and Medical Plan:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Pension Plan and SERP benefits	(in millions)			
Service cost	$0.2	$0.3	$0.6	$0.9
Interest cost	1.2	1.3	3.6	3.9
Expected return on plan assets	(1.3)	(1.4)	(4.0)	(4.2)
Amortization of prior service costs[1]	0.3	0.3	0.9	0.9
Amortization of actuarial losses[1]	0.1	0.2	0.3	0.6
Curtailment loss[2]	0.7	—	0.7	—
Periodic expense	$1.2	$0.7	$2.1	$2.1
Medical Plan benefits				
Interest cost	$—	$0.1	$0.1	$0.2
Amortization of prior service costs[1]	(0.1)	—	(0.2)	0.1
Periodic expense	$(0.1)	$0.1	$(0.1)	$0.3

(1) Amortization of prior service costs and actuarial losses out of accumulated other comprehensive income are recognized on the Condensed Consolidated Statements of Operations within "Interest and other income (expense)".

(2) A curtailment is recognized immediately when there is a significant reduction in, or an elimination of, defined benefit accruals for current employees' future services. These expenses relate to the Pinedale Divestiture and are recognized on the Condensed Consolidated Statements of Operations within "Gain (loss) from asset sales" for the three and nine months ended September 30, 2017.

Note 12 – Subsequent Event

On October 24, 2017, QEP closed on its previously announced acquisition of oil and gas properties in the Permian Basin for an aggregate purchase price of $683.5 million, subject to post-closing purchase price adjustments (the 2017 Permian Basin Acquisition). The 2017 Permian Basin Acquisition consists of approximately 13,000 acres, mainly in Martin County, Texas, which are held by production from existing vertical wells. Approximately 700 additional acres contracted for in the transaction were not included in the closing, but are expected to be acquired by the Company within the next 30 days for an aggregate purchase price not to exceed $38.0 million. Within 10 business days of closing the 2017 Permian Basin Acquisition, QEP is obligated to make offers to various persons who own additional oil and gas interests in certain properties included in the transaction on substantially the same terms and conditions as the purchase described above. If all offers are accepted, the aggregate purchase price is not expected to exceed $65.0 million. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded all of the purchase price with the proceeds from the Pinedale Divestiture.

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

Management’s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company’s operating results. MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and related Notes included in Part I, Item 1 of this Quarterly Report on Form 10-Q.

The following information updates the discussion of QEP's financial condition provided in its Annual Report on Form 10-K for the year ended December 31, 2016 (2016 Form 10-K) and analyzes the changes in the results of operations between the three and nine months ended September 30, 2017 and 2016. For definitions of commonly used oil and gas terms found in this Quarterly Report on Form 10-Q, please refer to the "Glossary of Terms" provided in the 2016 Form 10-K.

OVERVIEW

QEP Resources, Inc. is an independent crude oil and natural gas exploration and production company focused in two regions of the United States: the Northern Region (primarily in North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

The Company has substantial acreage positions and operations in some of the most prolific hydrocarbon resource plays in the continental United States, including the Permian Basin, Williston Basin, Haynesville Shale and Uinta Basin. These resource plays are characterized by unconventional oil or gas accumulations in continuous tight sands, carbonates or shales that underlie broad geographic areas. The lateral continuity of such resource plays means that, aside from wells abandoned due to mechanical issues, the Company does not expect to drill many unsuccessful wells as it develops these resource plays. Resource plays allow the Company the opportunity to gain considerable operational efficiencies through high-density, repeatable drilling and completion operations. The Company believes it has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore U.S., which provide a solid base for organic growth in production and reserves.

While historically the Company has been more heavily natural gas-weighted, in recent years the Company has increased its focus on growing oil production and reserves. Since the beginning of 2012, the Company has acquired approximately $3.9 billion of oil-weighted properties and sold gas-weighted properties, such as Pinedale. In addition, beginning in 2012, the Company has invested approximately 60% of its capital expenditures (excluding property acquisitions) on its oil-weighted properties. The Company has emphasized development of its oil-weighted Permian Basin assets by increasing its oil production by 37% during the nine months ended September 30, 2017, compared to the nine months ended September 30, 2016.

Outlook

Since the commodity price downturn in late 2014, the Company has focused on lowering operating costs, reducing per-well drilling costs and managing its liquidity. We believe our strong balance sheet and ample liquidity will allow us to grow oil production, primarily in the Permian Basin, and gas production, primarily in Haynesville/Cotton Valley, during 2017.

Based on current commodity prices, we expect to be able to fund our planned capital program for the remainder of 2017 with cash on hand, cash flow from operating activities and borrowings under our credit facility. Our total capital expenditures (excluding property acquisitions), for 2017 are expected to be approximately $1,075.0 million, an increase of approximately 100% from 2016 capital expenditures. We continuously evaluate our level of drilling and completion activity in light of drilling results, commodity prices and changes in our operating and development costs and may make adjustments to our capital investment program based on such evaluations. See "Cash Flow from Investing Activities" for further discussion of our capital expenditures.

Acquisitions and Divestitures

While QEP believes its extensive inventory of identified drilling locations provides a solid base for growth in production and reserves, the Company continues to evaluate and acquire properties in its existing areas of operations to add additional acreage and facilitate the drilling of long lateral wells. QEP believes that its experience, expertise and presence in its core operating areas, combined with its low-cost operating model and financial strength, enhances its ability to pursue acquisition opportunities. The Company continuously evaluates potential acquisition, divestiture and joint venture opportunities that align with its strategic objectives. To simplify its asset portfolio and to provide additional liquidity for future growth, QEP is evaluating the sale of certain upstream and midstream assets.

Acquisitions
During the nine months ended September 30, 2017, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage and additional surface acreage in the Permian Basin, for an aggregate purchase price of $94.5 million. In conjunction with these acquisitions, the Company recorded $5.3 million of goodwill. During the nine months ended September 30, 2016, QEP acquired various oil and gas properties, which primarily included additional interests in QEP's operated wells and additional undeveloped leasehold acreage in the Permian and Williston basins, for an aggregate purchase price of $46.1 million. In conjunction with the acquisitions, the Company recorded $3.7 million of goodwill, which was subsequently impaired in 2016, and a $4.4 million bargain purchase gain.

In addition, in October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $591.0 million, subject to customary post-closing purchase price adjustments (the 2016 Permian Basin Acquisition). The 2016 Permian Basin Acquisition consisted of approximately 9,600 net acres in Martin County, Texas, which are primarily held by production from existing vertical wells. The 2016 Permian Basin Acquisition was funded with cash on hand, which included proceeds from an equity offering in June 2016.

On October 24, 2017, QEP closed on its previously announced acquisition of oil and gas properties in the Permian Basin for an aggregate purchase price of $683.5 million, subject to post-closing purchase price adjustments (the 2017 Permian Basin Acquisition). The 2017 Permian Basin Acquisition consists of approximately 13,000 acres, mainly in Martin County, Texas, which are held by production from existing vertical wells. Approximately 700 additional acres contracted for in the transaction were not included in the closing, but are expected to be acquired by the Company within the next 30 days for an aggregate purchase price not to exceed $38.0 million. Within 10 business days of closing the 2017 Permian Basin Acquisition, QEP is obligated to make offers to various persons who own additional oil and gas interests in certain properties included in the transaction on substantially the same terms and conditions as the purchase described above. If all offers are accepted, the aggregate purchase price is not expected to exceed $65.0 million. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded all of the purchase price with the proceeds from the Pinedale Divestiture.

Divestitures
In September 2017, QEP closed on its previously announced divestiture of its assets in Pinedale (the Pinedale Divestiture), for net cash proceeds (after purchase price adjustments) of $718.2 million, subject to post-closing purchase price adjustments, and recorded a pre-tax gain on sale of $178.8 million which was recorded within "Net gain (loss) from asset sales" on the Condensed Consolidated Statements of Operations.

In addition to the Pinedale Divestiture, during the nine months ended September 30, 2017, QEP received proceeds of $69.7 million and recorded a pre-tax gain on sale of $26.4 million, primarily related to the divestiture of certain non-core properties in the Other Northern area. During the nine months ended September 30, 2016, QEP received proceeds of $28.9 million and recorded a pre-tax gain on sale of $5.0 million, primarily related to the divestiture of certain non-core properties in the Other Southern area.

On October 13, 2017, QEP closed on the divestiture of its Central Basin Platform assets and received net cash proceeds of $3.5 million. Refer to Note 4 – Capitalized Exploratory Well Costs, in Item I of Part I of this Quarterly Report on Form 10-Q for more information.

Financial and Operating Results

During the three months ended September 30, 2017, QEP:

- Closed the Pinedale Divestiture, for net cash proceeds (after purchase price adjustments) of $718.2 million, subject to post-closing purchase price adjustments, and recorded a pre-tax gain on sale of $178.8 million;
- Delivered oil production of 4,827.1 Mbbls, including a record 1,692.8 Mbbls in the Permian Basin and 2,803.3 Mbbls in the Williston Basin;
- Increased gas production in Haynesville/Cotton Valley to 19.9 Bcf, a 64% increase over 2016 volumes, due to a successful refracturing program;
- Reported realized oil prices of $47.67 per bbl, a 9% increase over 2016, realized gas prices of $2.79 per Mcf, a 6% increase over 2016 and realized NGL prices of $21.28 per bbl, a 74% increase over 2016;
- Generated a net loss of $3.3 million, or $0.01 per diluted share; and
- Reported Adjusted EBITDA (a non-GAAP financial measure defined and reconciled below) of $193.1 million, a 14% increase over 2016.

During the nine months ended September 30, 2017, QEP:

- Delivered oil production of 14,380.1 Mbbls, including a record 4,144.1 Mbbls in the Permian Basin and 9,216.5 Mbbls in the Williston Basin;
- Increased gas production in Haynesville/Cotton Valley to 48.8 Bcf, a 62% increase over 2016 volumes, due to a successful refracturing program;
- Reported realized oil prices of $47.10 per bbl, a 15% increase over 2016, realized gas prices of $2.81 per Mcf, an 11% increase over 2016 and realized NGL prices of $19.89 per bbl, a 59% increase over 2016;
- Generated net income of $119.0 million, or $0.49 per diluted share; and
- Reported Adjusted EBITDA (a non-GAAP financial measure defined and reconciled below) of $541.0 million, a 19% increase over 2016.

Factors Affecting Results of Operations

Supply, Demand, Market Risk and their Impact on Oil and Gas Prices
Oil and gas prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors. In recent years, oil and gas prices have been affected by supply growth, particularly in U.S. oil and gas production, driven by advances in drilling and completion technologies, and fluctuations in demand driven by a variety of factors.

Changes in the market prices for oil, gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling and completion activity and related capital expenditures, our proved undeveloped (PUD) reserves conversion rate, liquidity, rate of growth, costs of goods and services required to drill, complete and operate wells, and the carrying value of its oil and gas properties. Historically, field-level prices received for QEP’s oil and gas production have been volatile. During the past five years, the posted price for WTI crude oil has ranged from a low of $26.19 per barrel in February 2016 to a high of $110.62 per barrel in September 2013. The Henry Hub spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $8.15 per MMBtu in February 2014. If prices of oil, gas and NGL decline to early 2016 levels or further, our operations, financial condition and level of expenditures for the development of our oil and gas reserves may be materially and adversely affected.

NGL prices have also been volatile due to increased U.S. hydrocarbon production and insufficient domestic demand and export capacity. In addition to commodity price movements, QEP's composite NGL prices are affected by ethane recovery or rejection. When ethane is recovered as a discrete NGL component instead of being sold as part of the natural gas stream, the average sales price of a NGL barrel decreases as the ethane price is generally lower than the prices of the remaining NGL components. As permitted in some of its processing agreements, QEP recovers ethane when gas processing economics support the recovery of ethane from the natural gas stream. When gas processing economics do not support ethane recovery, and processing agreements permit it to do so, QEP elects to reject ethane from the NGL stream. In instances where QEP can make an election, QEP rejected ethane during the nine months ended September 30, 2017, and will likely continue to reject ethane for the remainder of 2017.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including Europe and China's economic outlook; the Organization of Petroleum Exporting Countries (OPEC) countries oil production and policies regarding production quotas; political unrest and economic issues in certain countries in South America, Asia, Europe, the Middle East, and Africa; slowing growth in certain emerging market economies; actions taken by the U.S. Congress and the president of the United States; the U.S. federal budget deficit; changes in regulatory oversight policy; commodity price volatility; the impact of a potential increase in interest rates; volatility in various global currencies; and other factors. A dramatic decline in regional or global economic conditions, a major recession or depression, regional political instability, economic sanctions, war, or other factors beyond the control of QEP could have a significant impact on oil, gas and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs and could materially impact the Company's financial position, results of operations and cash flow from operations. In December 2015, the U.S. lifted a 40-year ban on the export of oil, giving U.S. producers access to a wider market. As a result, the U.S. may in the future become a significant exporter of oil if the necessary infrastructure is built to support oil exports. Disruption to the global oil supply system, political and/or economic instability, fluctuations in currency values, and/or other factors could trigger additional volatility in oil prices.

Due to continued global economic uncertainty and the corresponding volatility of commodity prices, QEP continues to maintain a strong liquidity position to ensure financial flexibility. QEP uses commodity derivatives to reduce the volatility of the prices QEP receives for a portion of its production and to partially protect cash flow and returns on invested capital from a drop in commodity prices. Generally, QEP intends to enter into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. At September 30, 2017, QEP forecasted its 2017 annual production to be approximately 53.2 MMboe and had approximately 71% of its forecasted oil production and 80% of its forecasted gas production covered with fixed-price swaps and collars. See Part 1, Item 3 – "Quantitative and Qualitative Disclosures about Market Risk-Commodity Price Risk Management" for further details on QEP’s commodity derivatives transactions.

Potential for Future Asset Impairments
The carrying values of the Company’s properties are sensitive to declines in oil, gas and NGL prices as well as increases in various development and operating costs and expenses and, therefore, are at risk of impairment. The Company uses a cash flow model to assess its proved properties for impairment. The cash flow model includes numerous assumptions, including estimates of future oil, gas and NGL production, estimates of future prices for production that are based on the price forecast that management uses to make investment decisions, including estimates of basis differentials, future operating costs, transportation expenses, production taxes, and development costs that management believes are consistent with its price forecast, and discount rates. Management also considers a number of other factors, including the forward curve for future oil and gas prices, and developments in regional transportation infrastructure when developing its estimate of future prices for production. All inputs for the cash flow model are evaluated at each date of estimate.

We base our fair value estimates on projected financial information that we believe to be reasonably likely to occur. An assessment of the sensitivity of our capitalized costs to changes in the assumptions in our cash flow calculations is not practicable, given the numerous assumptions (e.g., future oil, gas and NGL prices; production and reserves; pace and timing of development plans; timing of capital expenditures; operating costs; drilling and development costs; and inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced oil, gas and NGL prices on future undiscounted cash flows would likely be offset by lower drilling and development costs and lower operating costs.

During the nine months ended September 30, 2017, QEP recorded impairment charges of $28.4 million, which was primarily related to unproved leasehold acreage in the Central Basin Platform. Refer to Note 4 – Capitalized Exploratory Well Costs, in Item I of Part I of this Quarterly Report on Form 10-Q for more information.

During the nine months ended September 30, 2016, the Company recorded impairments of $1,188.2 million, of which $1,167.9 million was related to proved properties due to lower future prices, primarily in Pinedale, $16.6 million was related to expiring leaseholds on unproved properties and $3.7 million was related to an impairment of goodwill.

If forward oil prices decline from September 30, 2017 levels or we experience negative changes in estimated reserve quantities, as of September 30, 2017, we have proved and unproved property with a net book value of approximately $2.7 billion at risk for impairment, primarily associated with our Williston Basin field. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates.

Multi-Well Pad Drilling
To reduce the costs of well location construction and rig mobilization and demobilization and to obtain other efficiencies, QEP utilizes multi-well pad drilling where practical. For example, in the Permian Basin QEP utilizes "tank style" development, in which we drill and complete all wells in a given "tank" before any individual well is turned to production. In certain of our producing areas, wells drilled on a pad are not completed and brought into production until all wells on the pad are drilled and the drilling rig is moved from the location. As a result, multi-well pad drilling delays the completion of wells and the commencement of production. In addition, existing wells that offset new wells being completed by QEP or offset operators may need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP’s quarterly operating results. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed.

Uncertainties Related to Claims
QEP is currently subject to claims that could adversely impact QEP’s liquidity, operating results and/or capital expenditures for a particular reporting period, including, but not limited to those described in Note 9 – Commitments and Contingencies, in Item 1 of Part I of this Quarterly Report on Form 10-Q. Given the uncertainties involved in these matters, QEP is unable to predict the ultimate outcomes.

Critical Accounting Estimates
QEP's significant accounting policies are described in Item 7 of Part II of its 2016 Form 10-K. The Company's Condensed Consolidated Financial Statements are prepared in accordance with GAAP. The preparation of the Company's Condensed Consolidated Financial Statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. QEP's accounting policies on oil and gas reserves, successful efforts accounting for oil and gas operations, impairment of long-lived assets, asset retirement obligations, revenue recognition, litigation and other contingencies, environmental obligations, derivative contracts, pension and other postretirement benefits, share-based compensation, income taxes and purchase price allocations, among others, may involve a high degree of complexity and judgment on the part of management.

Drilling and Completion Activity
The following table presents operated and non-operated well completions for the three and nine months ended September 30, 2017:

	Operated Completions				Non-operated Completions			
	Three Months Ended September 30, 2017		Nine Months Ended September 30, 2017		Three Months Ended September 30, 2017		Nine Months Ended September 30, 2017	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Williston Basin	8	6.8	31	26.0	6	0.1	20	0.4
Pinedale	12	4.1	20	8.6	—	—	—	—
Uinta Basin	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	10	10.0	42	41.7	—	—	—	—
Haynesville/Cotton Valley	—	—	—	—	—	—	8	0.8

Other Southern	—	—	—	—	——	—	—

QEP continues to refine its development methodology in the Permian Basin which may result in drilling and/or completion delays that may negatively impact planned PUD reserve conversions during 2017.

The following table presents operated and non-operated wells in the process of being drilled or waiting on completion at September 30, 2017:

		Operated				Non-operated			
	Drilling	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Rigs	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region									
Williston Basin	1	1	0.9	1	0.9	—	—	7	0.1
Pinedale	—	—	—	—	—	—	—	—	—
Uinta Basin	—	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—	—
Southern Region									
Permian Basin(1)(2)	6	38	37.8	29	29.0	—	—	—	—
Haynesville/Cotton Valley	1	1	1	—	—	5	0.3	7	0.1
Other Southern	—	—	—	—	—	—	—	—	—

(1) In addition to the drilling rigs in the table above, there is one rig in the Permian Basin drilling salt water disposal wells.

(2) The gross operated drilling well count in the Permian Basin includes 21 wells for which surface casing has been set, but as of September 30, 2017, did not have a rig drilling.

The term "gross" refers to all wells or acreage in which QEP has at least a partial working interest and the term "net" refers to QEP's ownership represented by that working interest. Each gross well completed in more than one producing zone is counted as a single well. QEP typically utilizes multi-well pad drilling where practical. For example, in the Permian Basin QEP utilizes "tank style" development, in which we drill and complete all wells in a given "tank" before any individual well is turned to production. Wells drilled are not completed and brought into production until all wells on the pad are drilled and the drilling rig is moved from the location. QEP sometimes suspends completion activities due to adverse weather conditions, operational factors or other macroeconomic circumstances, such as low commodity prices. QEP had 30 gross operated wells waiting on completion as of September 30, 2017.

RESULTS OF OPERATIONS

Net Income

QEP generated a net loss during the third quarter of 2017 of $3.3 million, or $0.01 per diluted share, compared to a net loss of $50.9 million, or $0.21 per diluted share, in the third quarter of 2016. QEP's decreased net loss was primarily due to a $180.1 million increase in net gain from asset sales, of which $178.8 million was due to the Pinedale Divestiture, a 10% increase in average realized prices, a $40.9 million decrease in depreciation, depletion and amortization, a $23.1 million decrease in general and administrative expenses and a $15.6 million decrease in transportation and processing costs. These changes were partially offset by a 2% decrease in oil equivalent production, $140.9 million increase in unrealized derivative losses, a $25.5 million increase in lease operating expense and a $23.3 million increase in impairment expense in the third quarter of 2017 compared to the third quarter of 2016.

QEP generated net income during the first three quarters of 2017 of $119.0 million, or $0.49 per diluted share, compared to a net loss of $1,111.7 million, or $5.15 per diluted share, in the first three quarters of 2016. QEP's increased net income was primarily due to a decrease in impairment expense of $1,159.8 million, a 14% increase in average realized prices, a $380.2 million increase in unrealized derivative gains, a $107.3 million decrease in depreciation, depletion and amortization, a $49.6 million decrease in general and administrative expenses and a $16.3 million decrease in transportation and processing costs. These changes were partially offset by a 2% decrease in oil equivalent production, a $52.1 million increase in lease operating expense and a $20.8 million increase in production and property tax expense in the first three quarters of 2017 compared to the first three quarters of 2016.

Adjusted EBITDA

Management defines Adjusted EBITDA as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment and certain other items. Management uses Adjusted EBITDA to evaluate QEP's financial performance and trends, make operating decisions and allocate resources. Management believes the measure is useful supplemental information for investors because it eliminates the impact of certain nonrecurring, non-cash and/or other items that management does not consider as indicative of QEP's performance from period to period. QEP's Adjusted EBITDA may be determined or calculated differently than similarly titled measures of other companies in our industry, which would reduce the usefulness of this non-GAAP financial measure when comparing our performance to that of other companies.

Below is a reconciliation of net income (loss) (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in millions)			
Net income (loss)	$(3.3)	$(50.9)	$119.0	$(1,111.7)
Interest expense	34.4	35.9	103.1	109.2
Interest and other (income) expense	(0.1)	(4.6)	(2.5)	(5.6)
Income tax provision (benefit)	(3.2)	(29.0)	69.7	(641.2)
Depreciation, depletion and amortization	176.9	217.8	560.2	667.5
Unrealized (gains) losses on derivative contracts	116.0	(24.9)	(161.6)	218.6
Exploration expenses	21.3	0.2	21.7	0.9
Net (gain) loss from asset sales	(185.4)	(5.3)	(205.2)	(5.0)
Impairment	28.3	5.0	28.4	1,188.2
Other[(1)]	8.2	25.0	8.2	32.7
Adjusted EBITDA	$193.1	$169.2	$541.0	$453.6

(1) Reflects legal expenses and loss contingencies incurred during the three and nine months ended September 30, 2017 and 2016. The Company believes that these amounts do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded these amounts from the calculation of Adjusted EBITDA.

Adjusted EBITDA increased to $193.1 million in the third quarter of 2017 from $169.2 million in the third quarter of 2016, primarily due to a 10% increase in average realized prices and a $15.6 million decrease in transportation and processing costs. These changes were partially offset by a 2% decrease in oil equivalent production and a $25.5 million increase in lease operating expense in the third quarter of 2017 compared to the third quarter of 2016.

Adjusted EBITDA increased to $541.0 million in the first three quarters of 2017 from $453.6 million in the first three quarters of 2016, primarily due to a 14% increase in average realized prices and a $16.3 million decrease in transportation and processing costs. These changes were partially offset by a 2% decrease in oil equivalent production, a $52.1 million increase in lease operating expense and a $20.8 million increase in production and property tax expense in the first three quarters of 2017 compared to the first three quarters of 2016.

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Revenue

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP's production-related revenue categories for the three and nine months ended September 30, 2017, compared to the three and nine months ended September 30, 2016:

	Oil	Gas	NGL	Total
	(in millions)			
Production revenues				
Three months ended September 30, 2016	$201.6	$123.2	$19.8	$344.6
Changes associated with volumes[1]	(7.9)	(0.4)	(1.3)	(9.6)
Changes associated with prices[2]	24.3	7.9	13.7	45.9
Three months ended September 30, 2017	$218.0	$130.7	$32.2	$380.9
Production revenues				
Nine months ended September 30, 2016	$553.1	$287.5	$56.2	$896.8
Changes associated with volumes[1]	(37.0)	3.7	(3.5)	(36.8)
Changes associated with prices[2]	139.6	108.2	31.3	279.1
Nine months ended September 30, 2017	$655.7	$399.4	$84.0	$1,139.1

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volume from the three and nine months ended September 30, 2017, as compared to the three and nine months ended September 30, 2016, by the average field-level price for the three and nine months ended September 30, 2016.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in average field-level price from the three and nine months ended September 30, 2017, as compared to the three and nine months ended September 30, 2016, by the respective volumes for the three and nine months ended September 30, 2017. Pricing changes are driven by changes in commodity average field-level prices, excluding the impact from commodity derivatives.

Production, Prices and Production Costs

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Total production volumes (Mboe)						
Northern Region						
Williston Basin	4,252.3	5,256.4	(1,004.1)	13,660.2	15,421.9	(1,761.7)
Pinedale	3,010.8	4,007.8	(997.0)	9,842.4	12,005.2	(2,162.8)
Uinta Basin	905.3	1,206.5	(301.2)	2,770.6	3,741.1	(970.5)
Other Northern	278.1	401.3	(123.2)	945.6	1,142.4	(196.8)
Southern Region						
Permian Basin	2,351.3	1,505.4	845.9	5,672.9	4,605.3	1,067.6
Haynesville/Cotton Valley	3,321.2	2,037.1	1,284.1	8,160.2	5,082.5	3,077.7
Other Southern	5.1	31.3	(26.2)	23.1	106.2	(83.1)
Total production	14,124.1	14,445.8	(321.7)	41,075.0	42,104.6	(1,029.6)
Total equivalent prices (per Boe)						
Average field-level equivalent price	$26.97	$ 23.86	$ 3.11	$27.73	$ 21.30	$ 6.43

Commodity derivative impact	0.83	1.35	(0.52)	0.05	3.10	(3.05)
Net realized equivalent price	$ 27.80	$ 25.21	$ 2.59	$ 27.78	$ 24.40	$ 3.38

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Oil Volumes and Prices

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Oil production volumes (Mbbl)						
Northern Region						
Williston Basin	2,803.3	3,625.5	(822.2)	9,216.5	11,142.8	(1,926.3)
Pinedale	124.0	161.1	(37.1)	404.7	486.9	(82.2)
Uinta Basin	169.7	190.0	(20.3)	498.3	596.6	(98.3)
Other Northern	30.0	44.1	(14.1)	94.2	114.6	(20.4)
Southern Region						
Permian Basin	1,692.8	989.9	702.9	4,144.1	3,018.0	1,126.1
Haynesville/Cotton Valley	6.8	6.3	0.5	19.7	20.2	(0.5)
Other Southern	0.5	8.2	(7.7)	2.6	31.9	(29.3)
Total production	4,827.1	5,025.1	(198.0)	14,380.1	15,411.0	(1,030.9)
Oil prices (per bbl)						
Northern Region	$44.63	$39.21	$5.42	$45.07	$34.90	$10.17
Southern Region	$46.13	$43.76	$2.37	$46.88	$39.86	$7.02
Average field-level price	$45.16	$40.12	$5.04	$45.60	$35.89	$9.71
Commodity derivative impact	2.51	3.81	(1.30)	1.50	5.18	(3.68)
Net realized price	$47.67	$43.93	$3.74	$47.10	$41.07	$6.03

Oil revenues increased $16.4 million, or 8%, in the third quarter of 2017 compared to the third quarter of 2016, due to higher average field-level prices, partially offset by lower oil production volumes. Average field-level oil prices increased 13% in the third quarter of 2017 compared to the third quarter of 2016 primarily driven by an increase in average NYMEX-WTI oil prices for the comparable periods combined with narrowing differentials in our Northern Region properties. The 4% decrease in production volumes was driven by decreases in the Williston and Uinta basins due to a reduction in completion activity as well as operational issues and well shut-ins associated with offset completion activity in the Williston Basin and a decrease in Pinedale as a result of the Pinedale Divestiture, which closed in September 2017. These decreases were partially offset by a production increase in the Permian Basin due to increased completion activity and the additional production from the 2016 Permian Basin Acquisition.

Oil revenues increased $102.6 million, or 19%, in the first three quarters of 2017 compared to the first three quarters of 2016, due to higher average field-level prices, partially offset by lower oil production volumes. Average field-level oil prices increased 27% in the first three quarters of 2017 compared to the first three quarters of 2016 primarily driven by an increase in average NYMEX-WTI oil prices for the comparable periods combined with narrowing differentials in our Northern Region properties. The 7% decrease in production volumes was driven by the Williston and Uinta basins and in Pinedale due to a reduction in completion activity throughout 2016 as well as operational issues and well shut-ins associated with offset completion activity in the Williston Basin as well as the Pinedale Divestiture. These decreases were partially offset by a production increase in the Permian Basin due to increased completion activity and the additional production from the 2016 Permian Basin Acquisition.

Gas Volumes and Prices

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
Gas production volumes (Bcf)						
Northern Region						
Williston Basin	3.7	4.3	(0.6)	11.8	11.5	0.3
Pinedale	15.8	21.1	(5.3)	51.9	62.7	(10.8)
Uinta Basin	4.1	5.7	(1.6)	12.9	17.9	(5.0)
Other Northern	1.4	2.1	(0.7)	5.0	6.1	(1.1)
Southern Region						
Permian Basin	1.8	1.3	0.5	4.3	4.3	—
Haynesville/Cotton Valley	19.9	12.1	7.8	48.8	30.2	18.6
Other Southern	—	0.2	(0.2)	0.1	0.4	(0.3)
Total production	46.7	46.8	(0.1)	134.8	133.1	1.7
Gas prices (per Mcf)						
Northern Region	$2.74	$2.62	$0.12	$2.95	$2.14	$0.81
Southern Region	$2.86	$2.65	$0.21	$2.97	$2.22	$0.75
Average field-level price	$2.80	$2.63	$0.17	$2.96	$2.16	$0.80
Commodity derivative impact	(0.01)	0.01	(0.02)	(0.15)	0.38	(0.53)
Net realized price	$2.79	$2.64	$0.15	$2.81	$2.54	$0.27

Gas revenues increased $7.5 million, or 6%, in the third quarter of 2017 compared to the third quarter of 2016, due to higher average field-level prices, partially offset by marginally lower gas production volumes. Average field-level gas prices increased 6% in the third quarter of 2017 compared to the third quarter of 2016, primarily driven by an increase in average NYMEX-HH gas prices for the comparable periods. The slight decrease in production volumes was primarily driven by production decreases in Pinedale and the Uinta Basin due to reduced completion activity throughout 2016 and the Pinedale Divestiture. These decreases were partially offset by increased production in Haynesville/Cotton Valley due to an operated well refracturing program that began in 2016 and continued throughout 2017.

Gas revenues increased $111.9 million, or 39%, in the first three quarters of 2017 compared to the first three quarters of 2016, due to higher average field-level prices and higher gas production volumes. Average field-level gas prices increased 37% in the first three quarters of 2017 compared to the first three quarters of 2016, primarily driven by an increase in average NYMEX-HH gas prices for the comparable periods. The 1% increase in production volumes was primarily driven by increased production in Haynesville/Cotton Valley due to an operated well refracturing program that began in 2016 and continued throughout 2017. This increase was partially offset by production decreases in Pinedale and the Uinta Basin due to reduced completion activity throughout 2016 and the Pinedale Divestiture.

NGL Volumes and Prices

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
NGL production volumes (Mbbl)						
Northern Region						
Williston Basin	834.7	920.8	(86.1)	2,480.6	2,362.7	117.9
Pinedale	255.5	333.8	(78.3)	779.5	1,069.9	(290.4)
Uinta Basin	42.3	56.0	(13.7)	117.3	157.6	(40.3)
Other Northern	3.8	7.6	(3.8)	12.0	17.3	(5.3)
Southern Region						
Permian Basin	376.0	288.6	87.4	823.6	860.9	(37.3)
Haynesville/Cotton Valley	4.9	6.0	(1.1)	13.6	20.6	(7.0)
Other Southern	(1.1)	3.7	(4.8)	(0.2)	13.8	(14.0)
Total production	1,516.1	1,616.5	(100.4)	4,226.4	4,502.8	(276.4)
NGL prices (per bbl)						
Northern Region	$21.89	$12.43	$9.46	$20.52	$12.87	$7.65
Southern Region	$19.43	$11.52	$7.91	$17.35	$10.95	$6.40
Average field-level price	$21.28	$12.26	$9.02	$19.89	$12.49	$7.40
Commodity derivative impact	—	—	—	—	—	—
Net realized price	$21.28	$12.26	$9.02	$19.89	$12.49	$7.40

NGL production volumes and revenues represent the sale of liquids derived from the processing of QEP's natural gas production. NGL revenues increased $12.4 million, or 63%, during the third quarter of 2017 compared to the third quarter of 2016, due to higher average field-level prices, partially offset by lower NGL production volumes. NGL prices increased 74% during the third quarter of 2017 compared to the third quarter of 2016, primarily driven by an increase in propane, ethane and other NGL component prices. The 6% decrease in NGL production volumes was driven by decreases in Pinedale due to reduced completion activity throughout 2016, our midstream provider withholding an additional 50.5 Mbbls to meet linefill requirements and the Pinedale Divestiture. The decrease in the Williston Basin is due to lower associated gas volumes and related NGL volumes from reduced completion activity. These decreases were partially offset by a production increase in the Permian Basin due to increased completion activity.

NGL revenues increased $27.8 million, or 49%, during the first three quarters of 2017 compared to the first three quarters of 2016, due to higher average field-level prices, partially offset by lower NGL production volumes. NGL prices increased 59% during the first three quarters of 2017 compared to the first three quarters of 2016, primarily driven by an increase in propane, ethane and other NGL component prices. The 6% decrease in NGL production volumes was driven by a decrease in Pinedale due to reduced completion activity, our midstream provider withholding an additional 50.5 Mbbls to meet linefill requirements and the Pinedale Divestiture. The increase in the Williston Basin is due to the resolution in November 2016 of a dispute with our midstream service provider that had negatively impacted gas volumes and associated NGL volumes in 2016.

Resale Margin and Storage Activity

QEP purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments and storage activities. The following table is a summary of QEP's financial results from its resale activities.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
	(in millions)					
Purchased oil and gas sales	$5.6	$35.3	$(29.7)	$44.5	$76.3	$(31.8)
Purchased oil and gas expense	(6.9)	(37.1)	30.2	(45.4)	(80.8)	35.4
Realized gains (losses) on gas storage derivative contracts	—	0.1	(0.1)	(0.2)	2.9	(3.1)
Resale margin	$(1.3)	$(1.7)	$0.4	$(1.1)	$(1.6)	$0.5

Purchased oil and gas sales decreased by $29.7 million, or 84%, during the third quarter of 2017 compared to third quarter of 2016, due to lower resale volumes, which is the result of increased production in areas where the Company has oil and gas transportation commitments.

Purchased oil and gas sales decreased by $31.8 million, or 42%, during the first three quarters of 2017 compared to first three quarters of 2016, due to lower resale volumes, which is the result of increased production in areas where the Company has oil and gas transportation commitments.

Purchased oil and gas expense, which includes transportation expense, decreased $30.2 million, or 81%, during the third quarter of 2017 compared to the third quarter of 2016, due to lower resale volumes as a result of increased production in areas where the Company has oil and gas transportation commitments.

Purchased oil and gas expense, which includes transportation expense, decreased $35.4 million, or 44%, during the first three quarters of 2017 compared to the first three quarters of 2016, due to lower resale volumes, which is the of result of increased production in areas where the Company has oil and gas transportation commitments.

Operating Expenses

The following table presents QEP production costs on a per unit of production basis:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Change	2017	2016	Change
	(per Boe)					
Lease operating expense	$5.39	$3.51	$1.88	$5.24	$3.88	$1.36
Transportation and processing costs	4.26	5.24	(0.98)	4.93	5.20	(0.27)
Production and property taxes	2.02	1.86	0.16	2.10	1.55	0.55
Total production costs	$11.67	$10.61	$1.06	$12.27	$10.63	$1.64

Lease operating expense (LOE). QEP’s LOE increased $25.5 million, or $1.88 per Boe, during the third quarter of 2017 compared to the third quarter of 2016. The increase in expense was driven by an increase in workovers in the Williston and Permian basins and in Haynesville/Cotton Valley and increased repairs and maintenance expense in the Williston Basin.

QEP's LOE increased $52.1 million, or $1.36 per Boe, during the first three quarters of 2017 compared to the first three quarters of 2016. The increase in expense was driven by an increase in workovers in the Williston and Permian basins and in Haynesville/Cotton Valley, increased repairs and maintenance expense in the Williston Basin and increased fuel expense in the Permian Basin.

Transportation and processing costs. Transportation and processing costs decreased $15.6 million, or $0.98 per Boe, during the third quarter of 2017 compared to the third quarter of 2016. The decrease in expense was primarily attributable to decreases in Haynesville/Cotton Valley and Pinedale. The decrease in Haynesville/Cotton Valley was primarily related to the recovery of fees for historical unutilized gathering and transportation capacity that was charged to QEP by the operator of wells in which QEP had a working interest. The decrease in Pinedale was primarily related to the recovery of historical transportation costs and the Pinedale Divestiture.

Transportation and processing costs decreased $16.3 million, or $0.27 per Boe, during the first three quarters of 2017 compared to the first three quarters of 2016. The decrease in expense was primarily attributable to decreases in Haynesville/Cotton Valley and Pinedale. The decrease in Haynesville/Cotton Valley was primarily related to the recovery of fees for historical unutilized gathering and transportation capacity that was charged to QEP by the operator of wells in which QEP had a working interest. The decrease in Pinedale was primarily related to the recovery of historical transportation costs and the Pinedale Divestiture.

Production and property taxes. In most states in which QEP operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume-based. Production and property taxes increased $1.7 million, or $0.16 per Boe, during the third quarter of 2017 compared to the third quarter of 2016, primarily as a result of increased oil and gas revenues from higher field-level prices, partially offset by lower production.

Production and property taxes increased $20.8 million, or $0.55 per Boe, during the first three quarters of 2017 compared to the first three quarters of 2016, primarily as a result of increased oil and gas revenues from higher field-level prices, partially offset by lower production.

Depreciation, depletion and amortization (DD&A). DD&A expense decreased $40.9 million in the third quarter of 2017 compared to the third quarter of 2016, primarily due to decreased rates in the Permian Basin and Haynesville/Cotton Valley. The lower rates in the Permian Basin and Haynesville/Cotton Valley are the result of higher proved reserves. In addition, QEP did not record DD&A expense in Pinedale during the third quarter of 2017 as the asset was considered held for sale prior to closing the Pinedale Divestiture in September 2017.

DD&A expense decreased $107.3 million in the first three quarters of 2017 compared to the first three quarters of 2016, primarily due to decreased rates in the Permian Basin, Pinedale and Haynesville/Cotton Valley. The Pinedale lower rate is a result of the 2016 impairment while the lower rates in the Permian Basin and Haynesville/Cotton Valley are a result of higher proved reserves. In addition, QEP did not record DD&A expense in Pinedale during the third quarter of 2017 as the asset was considered held for sale prior to closing the Pinedale Divestiture in September 2017.

Exploration expense. Exploration expense increased $21.1 million during the third quarter of 2017 compared to the third quarter of 2016, primarily as a result of charging $21.2 million of exploratory well costs related to the Central Basin Platform exploration project to exploration expense. During the third quarter of 2017, based on well performance and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project. Refer to Note 4 – Capitalized Exploratory Well Costs, in Item I of Part I of this Quarterly Report on Form 10-Q for more information.

Exploration expense increased $20.8 million during the first three quarters of 2017 compared to the first three quarters of 2016, primarily as a result of charging $21.2 million of exploratory well costs related to the Central Basin Platform exploration project to exploration expense. During the third quarter of 2017, based on well performance and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project. Refer to Note 4 – Capitalized Exploratory Well Costs, in Item I of Part I of this Quarterly Report on Form 10-Q for more information.

Impairment expense. During the third quarter of 2017, QEP recorded impairment charges of $28.3 million, which were primarily related to the impairment of unproved leasehold acreage in the Central Basin Platform. Refer to Note 4 – Capitalized Exploratory Well Costs, in Item I of Part I of this Quarterly Report on Form 10-Q for more information. During the third quarter of 2016, QEP recorded impairment charges of $5.0 million which was related to expiring leaseholds on unproved properties.

During the first three quarters of 2017, QEP recorded impairment charges of $28.4 million, which were primarily related to the impairment of unproved leasehold acreage in the Central Basin Platform. Refer to Note 4 – Capitalized Exploratory Well Costs, in Item I of Part I of this Quarterly Report on Form 10-Q for more information. During the first three quarters of 2016, QEP recorded impairment charges of $1,188.2 million, of which $1,167.9 million was related to proved properties due to lower future prices, $16.6 million was related to expiring leaseholds on unproved properties and $3.7 million related to an impairment of goodwill. Of the $1,167.9 million impairment on proved properties, $1,164.0 million related to Pinedale properties, $3.5 million related to Other Northern properties and $0.4 million related to Other Southern properties.

General and administrative (G&A) expense. During the third quarter of 2017, G&A expense decreased $23.1 million, or 35%, compared to the third quarter of 2016, primarily due to a $18.7 million decrease in legal expenses and loss contingencies, a $5.6 million decrease in share-based compensation from changes in the mark-to-market value of the Deferred Compensation Wrap Plan and Cash Incentive Plan (CIP) and a $1.0 million decrease in bad debt expense. These decreases were partially offset by increased labor, benefits and employee expenses of $2.4 million.

During the first three quarters of 2017, G&A expense decreased $49.6 million, or 31%, compared to the first three quarters of 2016, primarily due to a $27.4 million decrease in legal expenses and loss contingencies, a $22.9 million decrease in share-based compensation from changes in the mark-to-market value of the Deferred Compensation Wrap Plan and CIP, a $2.1 million decrease in bad debt expense and a $1.6 million decrease in severance and relocation expenses. These decreases were partially offset by increased labor, benefits and employee expenses of $4.3 million.

Net gain (loss) from asset sales. During the third quarter of 2017, QEP recognized a gain on the sale of assets of $185.4 million compared to a gain on the sale of assets of $5.3 million in the third quarter of 2016. The gain on the sale of assets in the third quarter of 2017 primarily related to the Pinedale Divestiture, in which we recorded a pre-tax gain on sale of $178.8 million, and the sale of non-core Other Northern properties. The gain on sale of assets in the third quarter of 2016 primarily related to continued divestitures of non-core Other Southern properties.

During the first three quarters of 2017, QEP recognized a gain on the sale of assets of $205.2 million compared to a gain on the sale of assets of $5.0 million in the first three quarters of 2016. The gain on the sale of assets in the first three quarters of 2017 primarily related to the Pinedale Divestiture, in which we recorded a pre-tax gain on sale of $178.8 million, and the sale of non-core Other Northern properties. The gain on sale of assets in the first three quarters of 2016 primarily related to continued divestitures of non-core Other Southern properties.

Non-operating Expenses

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative contracts are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts, which are marked-to-market each quarter. During the third quarter of 2017, losses on commodity derivative contracts were $104.3 million, of which $86.1 million were unrealized losses on derivative contracts related to production and storage contracts, $29.9 million were unrealized losses related to the Pinedale Divestiture (Refer to Note 7 – Derivative Contracts, in Item I of Part I of this Quarterly Report on Form 10-Q for more information) and $11.7 million were realized gains. During the third quarter of 2016, gains on commodity derivative contracts were $44.5 million, of which $24.9 million were unrealized gains and $19.6 million were realized gains.

During the first three quarters of 2017, gains on commodity derivative contracts were $163.3 million, of which $191.5 million were unrealized gains on derivative contracts related to production and storage contracts, $29.9 million were unrealized losses related to the Pinedale Divestiture (Refer to Note 7 – Derivative Contracts, in Item I of Part I of this Quarterly Report on Form 10-Q for more information) and $1.7 million were realized gains. During the first three quarters of 2016, losses on commodity derivative contracts were $85.1 million, of which $218.6 million were unrealized losses and $133.5 million were realized gains.

Interest expense. Interest expense decreased $1.5 million, or 4%, during the third quarter of 2017 compared to the third quarter of 2016. The decrease during the third quarter of 2017 was primarily related to the repayment of $176.8 million of senior notes in September 2016.

Interest expense decreased $6.1 million, or 6%, during the first three quarters of 2017 compared to the first three quarters of 2016. The decrease during the first three quarters of 2017 was primarily related to the repayment of $176.8 million of senior notes in September 2016.

Income tax (provision) benefit. Income tax benefit decreased $25.8 million during the third quarter of 2017 compared to the third quarter of 2016. The decrease in benefit was the result of a lower net loss, partially offset by a higher combined effective federal and state income tax rate of 49.2% during the third quarter of 2017 compared to a rate of 36.3% during the third quarter of 2016. The increase in income tax rate was primarily the result of recognizing a year to date adjustment for a permanent difference related to marginal well tax credits in the third quarter of 2017 as well as a change in income between different states.

Income tax expense increased $710.9 million during the first three quarters of 2017 compared to the first three quarters of 2016. The increase in expense was the result of net income before income taxes compared to a net loss, partially offset by a higher combined effective federal and state income tax rate of 36.9% during the first three quarters of 2017 compared to a rate of 36.6% during the first three quarters of 2016.

LIQUIDITY AND CAPITAL RESOURCES

QEP strives to maintain a strong liquidity position to ensure financial flexibility, withstand commodity price volatility and fund its development projects, operations and capital expenditures. The Company utilizes derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty to the Company’s cash flows. QEP generally funds its operations and planned capital expenditures with cash flow from its operating activities, cash on hand and borrowings under its revolving credit facility. The Company expects that these sources of cash will be sufficient to fund its operations, capital expenditures and repayment of its senior notes maturing during the next 12 months and the foreseeable future.

To provide additional liquidity, QEP also periodically accesses debt and equity markets and sells properties. In 2016, QEP issued 60.95 million shares of common stock through two public offerings and received net proceeds of approximately $781.4 million, which the Company used to fund the 2016 Permian Basin Acquisition and for general corporate purposes.

QEP received aggregate proceeds of approximately $787.9 million related to the Pinedale Divestiture and the sale of non-core properties during the nine months ended September 30, 2017. On October 24, 2017, QEP closed on its previously announced 2017 Permian Basin Acquisition for approximately $683.5 million and funded all of the purchase price of the acquisition with proceeds from the Pinedale Divestiture. Approximately 700 additional acres contracted for in the transaction were not included in the closing, but are expected to be acquired by the Company within the next 30 days for an aggregate purchase price not to exceed $38.0 million. Within 10 business days of closing the 2017 Permian Basin Acquisition, QEP is obligated to make offers to various persons who own additional oil and gas interests in certain properties included in the transaction on substantially the same terms and conditions as the purchase described above. If all offers are accepted, the aggregate purchase price is not expected to exceed $65.0 million. QEP received aggregate proceeds of approximately $28.9 million related to the sale of non-core properties during the nine months ended and September 30, 2016.

The Company estimates, that with its cash balance as of September 30, 2017, it could incur additional indebtedness of approximately $1.0 billion and continue to be in compliance with the covenants contained in its revolving credit facility. The Company estimates that as of October 24, 2017, after using cash to fund the Permian Basin Acquisition, it could incur additional indebtedness under its revolving credit facility of approximately $550.0 million and continue to be in compliance with the covenants contained in its revolving credit facility. To the extent actual operating results, realized commodity prices or uses of cash differ from the Company’s assumptions, QEP's liquidity could be adversely affected.

Credit Facility

QEP's revolving credit facility, which matures in December 2019, provides for loan commitments of $1.8 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%; (ii) a leverage ratio under which net funded debt may not exceed 4.25 times consolidated EBITDA (as defined in the credit agreement) for the fiscal quarters ending on and prior to December 31, 2017, 4.00 times for the quarters in fiscal year 2018, and 3.75 times thereafter and (iii) during a ratings trigger period, a present value coverage ratio which requires that the present value of the Company's proved reserves must exceed net funded debt by 1.25 times at any time prior to January 1, 2018, and 1.50 times at any time on or after January 1, 2018. The Company is currently not subject to the present value coverage ratio.

As of September 30, 2017 and December 31, 2016, QEP had no borrowings outstanding under the credit facility, had $1.0 million and $2.8 million, respectively, in letters of credit outstanding under the credit facility and was in compliance with the covenants under the credit agreement. As of October 24, 2017, QEP had no borrowings outstanding under the credit facility, had $1.0 million of letters of credit outstanding under the credit facility and was in compliance with the covenants under the credit agreement.

Senior Notes

The Company's senior notes outstanding as of September 30, 2017, totaled $2,045.0 million principal amount and are comprised of five issuances as follows:

- $134.0 million 6.80% Senior Notes due April 2018;
- $136.0 million 6.80% Senior Notes due March 2020;
- $625.0 million 6.875% Senior Notes due March 2021;
- $500.0 million 5.375% Senior Notes due October 2022; and
- $650.0 million 5.25% Senior Notes due May 2023.

The Company plans to repay its $134.0 million Senior Notes due April 2018 with cash on hand or borrowings under the credit facility.

Cash Flow from Operating Activities

Cash flows from operating activities are primarily affected by oil, gas and NGL production volumes and commodity prices (including the effects of settlements of the Company's derivative contracts) and by changes in working capital. QEP typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated future oil and gas production for the next 12 to 24 months.

Net cash provided by (used in) operating activities is presented below:

	Nine Months Ended September 30,		
	2017	2016	Change
	(in millions)		
Net income (loss)	$119.0	$(1,111.7)	$1,230.7
Non-cash adjustments to net income (loss)	318.7	1,516.4	(1,197.7)
Changes in operating assets and liabilities	44.1	128.2	(84.1)
Net cash provided by (used in) operating activities	$481.8	$532.9	$(51.1)

Net cash provided by operating activities was $481.8 million during the first three quarters of 2017, which included $119.0 million of net income, $318.7 million of non-cash adjustments to net income and a $44.1 million increase in operating assets and liabilities. Non-cash adjustments to net income primarily included DD&A expense of $560.2 million and $68.5 million of deferred income taxes, partially offset by a net gain on asset sales of $205.2 million and unrealized gains on derivative contracts of $161.6 million. The increase in cash from operating assets and liabilities primarily resulted from a decrease in accounts receivable of $18.5 million, an increase in accounts payable and accrued expenses of $17.8 million and an increase in production and property taxes of $7.3 million, partially offset by a decrease in the ARO liability of $3.0 million.

Net cash provided by operating activities was $532.9 million during the first three quarters of 2016, which included a $1,111.7 million net loss, $1,516.4 million of non-cash adjustments to the net loss and a $128.2 million increase in operating assets and liabilities. Non-cash adjustments to the net loss primarily included impairment expense of $1,188.2 million, DD&A expense of $667.5 million and unrealized losses on derivative contracts of $218.6 million, partially offset by a decrease in deferred income taxes of $581.1 million. The increase in operating assets and liabilities primarily included a decrease in accounts receivable of $115.4 million and a decrease in income taxes receivable of $64.8 million, primarily related to a federal income tax refund received in the third quarter of 2016, partially offset by a decrease in accounts payable and accrued expenses of $69.0 million.

Cash Flow from Investing Activities

During the first three quarters of 2017, net cash used in investing activities was $122.8 million compared to net cash used in investing activities of $452.2 million in the first three quarters 2016.

A comparison of capital expenditures for the first three quarters of 2017 and 2016, are presented in the table below:

	Nine Months Ended September 30,		
	2017	2016	Change
	(in millions)		
Property acquisitions (including acquisition deposits held in escrow)	$131.1	$76.1	$55.0
Property, plant and equipment capital expenditures	847.6	384.6	463.0
Total accrued capital expenditures	978.7	460.7	518.0
Change in accruals and other non-cash adjustments	(68.0)	20.4	(88.4)
Total cash capital expenditures	$910.7	$481.1	$429.6

In the first three quarters of 2017, on an accrual basis, the Company invested $847.6 million on property, plant and equipment capital expenditures, excluding property acquisitions, an increase of $463.0 million compared to the first three quarters of 2016. In the first three quarters of 2017, QEP's significant capital expenditures were $489.1 million in the Permian Basin, $195.4 million in the Williston Basin, $121.2 million in Haynesville/Cotton Valley and $24.8 million in Pinedale. In addition, in the first three quarters of 2017, QEP acquired various oil and gas properties, primarily proved and unproved leaseholds and additional surface acreage primarily in the Permian Basin, for an aggregate purchase price of $94.5 million. Lastly, QEP paid a deposit of $36.6 million, which is held in escrow related to the 2017 Permian Basin Acquisition that closed on October 24, 2017. These cash outflows were partially offset by proceeds from the Pinedale Divestiture, which closed in the third quarter of 2017, and the sale of other non-core assets of approximately $787.9 million.

In the first three quarters of 2016, on an accrual basis, the Company invested $384.6 million on property, plant and equipment capital expenditures, excluding property acquisitions, which included $184.0 million in the Williston Basin, $102.0 million in the Permian Basin, $44.9 million in Pinedale, $38.1 million in Haynesville/Cotton Valley and $10.4 million in the Uinta Basin. In addition, during the first three quarters of 2016, QEP acquired various oil and gas properties in the Williston and Permian basins, primarily to acquire additional interests in QEP's operated wells and additional undeveloped leasehold acreage, for a total purchase price of $46.1 million, of which $39.9 million was cash and $6.2 million was non-cash related to the settlement of an accounts receivable balance. Lastly, QEP paid a deposit of $30.0 million, which was held in escrow related to the 2016 Permian Basin Acquisition.

The mid-point of our 2017 forecasted capital expenditures (excluding property acquisitions) is $1,075.0 million with the majority of the funds directed towards drilling and completion activity. Nearly 60% of our planned capital investment is allocated to the Permian Basin, and approximately $70.0 to $80.0 million of investment is budgeted for midstream infrastructure, primarily in the Permian Basin. Based on current commodity prices, QEP intends to fund its 2017 forecasted capital expenditures (excluding acquisitions) with cash flow from operating activities and cash on hand and borrowings under our revolving credit facility. The aggregate levels of capital expenditures for 2017 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, oil, gas and NGL prices, industry conditions, the extent to which properties or working interests are acquired, the availability of capital resources to fund the expenditures and changes in management’s business assessments as to where QEP’s capital can be most profitably deployed. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from QEP’s estimates.

Cash Flow from Financing Activities

In the first three quarters of 2017, net cash used in financing activities was $20.2 million compared to net cash provided by financing activities of $575.4 million in the first three quarters of 2016. During the first three quarters of 2017, QEP had a decrease in checks outstanding in excess of cash balances of $12.3 million, had treasury stock repurchases of $6.8 million and paid long-term debt issuance costs of $1.1 million. During the first three quarters of 2016, QEP had net proceeds from the March and June 2016 equity offerings of approximately $781.6 million, a repayment of senior notes of $176.8 million and a decrease in checks outstanding in excess of cash balances of $25.5 million.

As of September 30, 2017, the Company did not have any borrowings outstanding under the credit facility and had $2,045.0 million in senior notes outstanding (excluding $20.4 million of net original issue discount and unamortized debt issuance costs).

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

QEP’s primary market risks arise from changes in the market price for oil, gas and NGL and volatility in interest rates. These risks can affect revenues and cash flows from operating, investing and financing activities. Commodity prices have historically been volatile and are subject to wide fluctuations in response to relatively minor changes in supply and demand. If commodity prices fluctuate significantly, revenues and cash flow may significantly decrease or increase. QEP has long-term contracts for pipeline capacity and is obligated to pay for transportation services with no guarantee that it also will be able to fully utilize the contractual capacity of these transportation commitments. In addition, additional non-cash impairment expense of the Company’s oil and gas properties may be required if future oil and gas commodity prices experience a significant decline. Furthermore, the Company’s credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. To partially manage the Company’s exposure to these risks, QEP enters into commodity derivative contracts in the form of fixed-price and basis swaps and collars to manage commodity price risk and periodically enters into interest rate swaps to manage interest rate risk.

Commodity Price Risk Management

QEP uses commodity derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments currently utilized by the Company are fixed-price and basis swaps and collars. The volume of commodity derivative instruments utilized by the Company may vary from year to year based on QEP's forecasted production. The Company's current derivative instruments do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of September 30, 2017, QEP held commodity price derivative contracts totaling 21.9 million barrels of oil, 154.5 million MMBtu of gas and 0.8 million MMBtu of net gas storage.

The following tables present QEP's volumes and average prices for its derivative positions as of October 20, 2017. See Note 7 – Derivative Contracts in Part 1, Item 1 of this Quarterly Report on Form 10-Q for open derivative positions as of September 30, 2017.

Production Commodity Derivative Swaps

Year	Index	Total Volumes	Average Swap Price per Unit
		(in millions)	
Oil sales		(bbls)	($/bbl)
2017	NYMEX WTI	3.6	$ 51.51
2018	NYMEX WTI	15.7	$ 52.37
2019	NYMEX WTI	4.4	$ 50.37
Gas sales		(MMBtu)	($/MMBtu)
2017	NYMEX HH	16.5	$ 2.87
2017	IFNPCR	4.3	$ 2.49
2018	NYMEX HH	109.5	$ 2.99
2019	NYMEX HH	25.6	$ 2.87

Production Commodity Derivative Basis Swaps

Year	Index Less Differential	Index	Total Volumes	Weighted-Average Differential
			(in millions)	
Oil sales			(bbls)	($/bbl)
2017	NYMEX WTI	Argus WTI Midland	1.1	$ (0.67)
2018 (Full Year)	NYMEX WTI	Argus WTI Midland	7.3	$ (1.06)
2018 (July through December)	NYMEX WTI	Argus WTI Midland	0.7	$ (0.75)
2019	NYMEX WTI	Argus WTI Midland	3.3	$ (0.90)
Gas sales			(MMBtu)	($/MMBtu)
2018	NYMEX HH	IFNPCR	7.3	$ (0.16)

Gas Storage Commodity Derivative Swaps

Year	Type of Contract	Index	Total Volumes	Average Swap Price per Unit
			(in millions)	
Gas sales			(MMBtu)	($/MMBtu)
2017	SWAP	IFNPCR	1.4	$ 2.89
2018	SWAP	IFNPCR	0.5	$ 3.09
Gas purchases			(MMBtu)	($/MMBtu)
2017	SWAP	IFNPCR	0.8	$ 2.73

Changes in the fair value of derivative contracts from December 31, 2016 to September 30, 2017, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2016	$ (201.8)
Contracts settled	(1.7)
Change in oil and gas prices on futures markets	200.2
Contracts added	(7.0)
Net fair value of oil and gas derivative contracts outstanding at September 30, 2017	$ (10.3)

The following table shows the sensitivity of the fair value of oil and gas derivative contracts to changes in the market price of oil, gas and basis differentials:

	September 30, 2017
	(in millions)
Net fair value – asset (liability)	$ (10.3)
Fair value if market prices of oil, gas and basis differentials decline by 10%	$ (11.2)
Fair value if market prices of oil, gas and basis differentials increase by 10%	$ (9.2)

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $1.1 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $0.9 million as of September 30, 2017. However, a gain or loss eventually would be offset by the actual sales value of the physical production covered by the derivative instruments. For additional information regarding the Company’s commodity derivative transactions, see Note 7 – Derivative Contracts in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Interest Rate Risk Management

The Company’s ability to borrow and the rates offered by lenders can be adversely affected by illiquid credit markets and the Company's credit rating, as described in the risk factors in Item 1A of Part I of its 2016 Form 10-K. The Company’s revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. At September 30, 2017, the Company did not have any borrowings outstanding under its revolving credit facility.

The remaining $2,045.0 million of the Company’s debt is senior notes with fixed interest rates; therefore, it is not affected by interest rate movements. For additional information regarding the Company’s debt instruments, see Note 8 – Debt, in Item I of Part I of this Quarterly Report on Form 10-Q.

Forward-Looking Statements

The quarterly report contains information that includes or is based upon "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements give expectations or forecasts of future events. You can identify these statements by the fact that they do not relate strictly to historical or current facts. We use words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," and other words and terms of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements include statements relating to, among other things:

- estimates of future liability for deficiency charges in connection with the Pinedale Divestiture;
- additional restructuring costs related to the Pinedale Divestiture;
- acquisitions of additional properties after closing of the 2017 Permian Basin Acquisition and expected purchase prices of such properties;
- our growth strategies;
- our strong balance sheet and ample liquidity providing for the ability to grow oil production, primarily in the Permian Basin and gas production, primarily in Haynesville/Cotton Valley;
- funding our planned capital program for the remainder of 2017 with cash on hand, cash flow from operating activities, and borrowings under our credit facility;
- our liquidity and the sufficiency of our cash flows from operations, cash on hand and borrowings under our credit facility to fund our operations, capital expenditures and the repayment of our senior notes maturing in the next 12 months and the foreseeable future;
- evaluating the sale of certain upstream and midstream assets to simplify our asset portfolio and provide additional liquidity for future growth;
- plans and ability to pursue acquisition opportunities;
- our inventory of drilling locations;
- drilling and completion plans and strategies;
- predictability and success of our drilling operations;
- plans to grow oil and gas production;
- oil exports from and imports to the U.S.;
- future development costs;
- estimates of the amount of additional indebtedness we may incur under our revolving credit facility;
- loss contingencies;
- expectations regarding oil, gas and NGL prices;
- plans to recover or reject ethane from produced natural gas;
- pro forma results for acquired properties;
- impact of lower or higher commodity prices and interest rates;
- volatility of oil, gas and NGL prices and factors impacting such prices;
- impact of global geopolitical and macroeconomic events;
- plans regarding derivative contracts and the anticipated benefits from our derivative contracts;
- divestitures of assets;
- incurring penalties and capital expenditures to address air emission noncompliance issues;
- amount and allocation of forecasted capital expenditures (excluding acquisitions), plans for funding operations and capital investments and adjustments to our capital investment program;
- assumptions regarding share-based compensation;
- settlement of performance share units in cash;
- recognition of compensation costs related to share-based compensation grants;
- expected contributions to our employee benefit plans;

- the usefulness of Adjusted EBITDA (a non-GAAP financial measure) and adjustments made to net income to arrive at Adjusted EBITDA;
- delays and volatility to operating results caused by multi-well pad drilling, including "tank-style" development;
- delays in proved undeveloped reserve conversions;
- estimated proved reserves and development of such reserves;
- fair values and critical accounting estimates, including estimated asset retirement obligations;
- implementation and impact of new accounting pronouncements;
- impact and growth of government regulations;
- impact of shutting in wells;
- potential for asset impairments and factors impacting impairment amounts;
- managing counterparty risk exposure; and
- outcome and impact of various claims.

Any or all forward-looking statements may turn out to be incorrect. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. These statements are based on current expectations and the current economic environment. They involve a number of risks and uncertainties that are difficult to predict. These statements are not guarantees of future performance. Actual results could differ materially from those expressed or implied in the forward-looking statements. Factors that could cause actual results to differ materially include, but are not limited to the following:

- the risk factors discussed in Item 1A of Part I of the 2016 Form 10-K and Item 1A of Part II of this Quarterly Report on Form 10-Q;
- changes in oil, gas and NGL prices;
- global geopolitical and macroeconomic factors;
- general economic conditions, including the performance of financial markets and interest rates;
- asset impairments;
- liquidity constraints, including those resulting from the cost and availability of debt and equity financing;
- drilling and completion strategies, methods and results;
- assumptions around well density/spacing and recoverable reserves per well prove to be inaccurate;
- shortages of oilfield equipment, services and personnel;
- lack of available pipeline, processing and refining capacity;
- processing volumes and pipeline throughput;
- the risks and liabilities associated with acquired assets;
- risks associated with hydraulic fracturing;
- the outcome of contingencies such as legal proceedings;
- delays in obtaining permits and governmental approvals;
- operating risks such as unexpected drilling conditions and risks inherent in the production of oil and gas;
- weather conditions;
- changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning: the environment, climate change, greenhouse gas or other emissions, natural resources, fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal and other proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- derivative activities;
- potential financial losses or earnings reductions from our commodity price risk management programs;
- volatility in the commodity-futures market;
- failure of internal controls and procedures;
- failure of our information technology infrastructure or applications to prevent a cyberattack;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- production, severance and property taxation rates;
- discount rates;
- regulatory approvals and compliance with contractual obligations;
- actions of, or inaction by federal, state, local or tribal governments, foreign countries and the Organization of Petroleum Exporting Countries;
- lack of, or disruptions in, adequate and reliable transportation for our production;
- competitive conditions;
- production and sales volumes;
- actions of operators on properties in which we own an interest but do not operate;
- estimates of oil and gas reserve quantities;

- reservoir performance;
- operating costs;
- inflation;
- capital costs;
- creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners and other parties;
- volatility in the securities, capital and credit markets;
- actions by credit rating agencies and their impact on the Company; and
- other factors, most of which are beyond the Company’s control.

QEP undertakes no obligation to publicly correct or update the forward-looking statements in this Quarterly Report on Form 10-Q, in other documents, or on the Company's website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company’s Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended, the Exchange Act) as of September 30, 2017. Based on such evaluation, such officers have concluded that, as of September 30, 2017, the Company’s disclosure controls and procedures are designed and effective to ensure that information required to be disclosed in the Company’s reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms, and that information is accumulated and communicated to the Company’s management, including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating the Company’s disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company’s controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended September 30, 2017, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

EPA Request for Information – In July 2015, QEP received an information request from the EPA pursuant to Section 114(a) of the Clean Air Act. The information request sought facts and data about certain tank batteries in QEP's Williston Basin operations. QEP timely responded to the information requests. In August 2016, the EPA requested a conference to review this matter; this conference has been scheduled for November 2017. While no formal federal enforcement action has been commenced in connection with the tank batteries to date, QEP anticipates that resolution of this matter will likely result in monetary penalties and require QEP to incur additional capital expenditures to correct noncompliance issues. In addition, QEP signed a consent decree with the North Dakota Department of Health effective August 2017. Under the decree, QEP agreed to perform site inspections and repairs and to pay approximately $111,000 (subject to reduction if QEP takes certain remedial actions) to resolve alleged noncompliance associated with emissions from tank batteries.

ITEM 1A. RISK FACTORS

Risk factors relating to the Company are set forth in its Annual Report on Form 10-K for the year ended December 31, 2016. Below are material changes to such risk factors that have occurred during the three and nine months ended September 30, 2017.

QEP may be unable to dispose of assets on financially attractive terms, resulting in reduced cash proceeds. QEP continually evaluates its portfolio of assets relative to capital investments, divestitures and joint venture opportunities. The success of such activity depends, in part, upon QEP’s ability to identify suitable buyers or joint venture partners; assess potential transaction terms; negotiate agreements; and, if applicable, obtain required approvals. Various factors could materially affect QEP's ability to dispose of assets on terms acceptable to QEP. Such factors include, but are not limited to, current commodity prices, laws, regulations and the permitting process impacting oil and gas operations in the areas where the assets are located, covenants under QEP's credit agreement, tax impacts, willingness of the purchaser to assume certain liabilities such as asset retirement obligations, QEP's willingness to indemnify buyers for certain matters, and other factors. Inability to achieve a desired price for assets, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a reduction of cash proceeds, a loss on sale due to an excess of the asset's net book value over proceeds, or liabilities that must be settled in the future at amounts that are higher than QEP had expected.

QEP is subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect its cost of doing business and recording of proved reserves. QEP's operations are subject to extensive federal, state, tribal and local tax, energy, environmental, health and safety laws and regulations. The failure to comply with applicable laws and regulations can result in substantial penalties and may threaten the Company's authorization to operate.

Environmental laws and regulations are complex, change frequently and have tended to become more onerous over time. This regulatory burden on the Company's operations increases its cost of doing business and, consequently, affects its profitability. In addition to the costs of compliance, substantial costs may be incurred to take corrective actions at both owned and previously owned facilities. Accidental spills and leaks requiring cleanup may occur in the ordinary course of QEP's business. As standards change, the Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time, but now require remedial work to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, other damages, or injunctions that could limit the scope of QEP's planned operations.

Clean Air Act regulations at 40 C.F.R Part 60, Subpart OOOO (Subpart OOOO) became effective in 2012, with further amendments effective in 2013 and 2014. Subpart OOOO imposes air quality controls and requirements upon QEP's operations. Additionally, in June 2016, the Environmental Protection Agency (EPA) finalized closely related rules in new Subpart OOOOa to achieve additional methane and volatile organic compound reductions from certain activities in the oil and gas industry. The new rules include, among others, new requirements for finding and repairing leaks at new well sites and "reduced emission completion" requirements for hydraulically fractured oil and gas wells. The future status of Subpart OOOOa remains uncertain given ongoing litigation and administrative regulatory actions; however, the rules remain in effect as of the filing of this report. The regulatory uncertainty surrounding the implementation of this rule poses some complications for QEP’s operations and compliance efforts. Additionally, many states are adopting air permitting and other air quality control regulations specific to oil and gas exploration, production, gathering and processing that are more stringent than existing requirements under federal regulations.

In June 2016, the EPA also issued a Federal Implementation Plan (FIP) to implement the Federal Minor New Source Review Program on tribal lands for oil and gas production. The FIP primarily impacts QEP’s operations on the Fort Berthold Reservation in the Williston Basin and on the Uintah and Ouray Indian Reservations in the Uinta Basin. The FIP creates a permit-by-rule process for minor sources that also incorporates emission limits and other requirements under various federal air quality standards, applying them to a range of equipment and processes used in oil and gas production. However, the FIP does not apply in areas of ozone non-attainment. As a result, the EPA may impose area-specific regulations in parts of the Uinta Basin identified as tribal lands that may require additional emissions controls on existing equipment as a result of expected designation of a portion of the Uinta Basin as a marginal nonattainment area for ozone. The proposals will likely result in increased operating and compliance costs.

The FERC has jurisdiction over the operation of QEP's Clear Creek underground gas storage facility by virtue of the facility's connection to interstate pipelines (also subject to FERC jurisdiction) at both its inlet and outlet. Clear Creek is subject to specific FERC regulations governing interstate transmission facilities and activities, including but not limited to rates charged for transmission, open access/non-discrimination, and public disclosure via an electronic bulletin board of daily capacity and flows.

Regulatory requirements to reduce gas flaring and to further restrict emissions could have an adverse effect on our operations. Wells in the Williston Basin of North Dakota and the Permian Basin of Texas, where QEP has significant operations, produce natural gas as well as crude oil. Constraints in third party gas gathering and processing systems in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the North Dakota Industrial Commission, North Dakota's chief energy regulator adopted a policy to reduce the volume of natural gas flared from oil wells in the Williston Basin. The commission requires operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties may be imposed on certain wells that cannot meet the capture goals. It is possible that other states will require gas capture plans in the future to reduce flaring. Additionally, in November 2016, the Bureau of Land Management (BLM) finalized a new rule related to further controls on the venting and flaring of natural gas on BLM and tribal leases (the 2016 Venting and Flaring Rule). The rule took effect in January 2017. The 2016 Venting and Flaring Rule is the subject of active litigation in the U.S. District Court for the District of Wyoming and the U.S. District Court for the Northern District of California. Some provisions of the rule are in effect, including the royalty provisions. Other provisions, however, including those related to further controls on the venting and flaring of natural gas, do not take effect until January 2018. The BLM's attempted stay of those 2018 compliance dates pursuant to Section 705 of the Administrative Procedure Act was vacated by the U.S. District Court for the Northern District of California. In October 2017, however, the BLM published a proposed rule to temporarily suspend or delay the 2018 compliance dates until January 2019, while the BLM reviews the 2016 Venting and Flaring Rule, to avoid imposing temporary or permanent compliance costs on operators for requirements that might be rescinded or significantly revised in the near future. These state and federal gas capture requirements, and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

As a result of future legislation, certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated or modified, and QEP may be subject to the imposition of increased or new taxes. Legislation may be proposed in the future that could, if enacted into law, make significant changes to U.S. tax laws. Such changes could include the elimination or modification of U.S. federal income tax provisions currently available to QEP such as: (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain domestic production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, or could generally affect the taxes imposed on QEP, including the imposition of new U.S. federal, state or local taxes (including the imposition of, or increase in, production, severance, environmental, sales, gross receipts, or similar taxes), could increase the cost of exploration and development of oil and gas resources, which would negatively affect QEP’s financial condition and results of operations.

Federal and state hydraulic fracturing legislation or regulatory initiatives could increase QEP's costs and restrict its access to oil and gas reserves. Currently, well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve all aspects of oil and gas well design and operation. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and issued guidance related to this asserted regulatory authority. The EPA may be considering its existing regulatory authorities for possible avenues to further regulate hydraulic fracturing fluids and/or the components of those fluids. Additionally, the BLM finalized regulations in March 2015 regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal leases (the 2015 Hydraulic Fracturing Rule). The 2015 Hydraulic Fracturing Rule was set aside by the U.S. District Court for the District of Wyoming. The district court’s decision was appealed to the U.S. Court of Appeals for the Tenth Circuit. In

September 2017, the Tenth Circuit dismissed the litigation challenging the 2015 Hydraulic Fracturing Rule, noting that it was pointless to proceed given the BLM’s proposal to rescind the rule. The Tenth Circuit also vacated the lower court’s 2016 ruling that struck down the rule. The Tenth Circuit’s ruling, which is expected to become effective in mid-November, reinstates the 2015 Hydraulic Fracturing Rule, unless and until the BLM’s proposal to rescind the rule becomes final. The 2015 Hydraulic Fracturing Rule will increase the cost of drilling and completing any well requiring federal permits and could result in further delays in getting such permits to authorize drilling and completion activities on federal and tribal leases upon which QEP operates.

At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. If new or more stringent federal, state or local regulations, restrictions or moratoria are adopted in areas where QEP operates, QEP could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling or stimulating wells in some areas.

The EPA has been collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. In December 2016, the EPA released its final report on the potential impacts to drinking water resources from hydraulic fracturing. The results of this study, which concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances, could result in additional regulations, which could lead to operational burdens similar to those described above. In 2014, the EPA issued an advance notice of proposed rulemaking and initiated a public participation process under the Toxic Substances Control Act to seek comment on the information that should be reported or disclosed for hydraulic fracturing chemical substances and mixtures and the mechanisms for obtaining this information. It has been reported, however, that the Trump Administration has delayed issuing a proposed rule indefinitely.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and natural gas that we produce. Climate change, the costs that may be associated with its effects and the regulation of greenhouse gas (GHG) emissions have the potential to affect our business in many ways, including increasing the costs to provide our products and services, reducing the demand for and consumption of our products and services (due to changes in both costs and weather patterns) and the economic health of the regions in which we operate, all of which can create financial risks. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. In addition, legislative and regulatory responses related to GHG emissions and climate change may result in increased operating costs, delays in obtaining air pollution and other necessary permits for new or modified facilities and reduced demand for the oil, gas and NGL that QEP produces. Federal and state courts and administrative agencies are considering the scope and scale of climate change regulation under various laws pertaining to the environment, energy use and energy resource development. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, or banning the use of gasoline or diesel powered vehicles, which may reduce demand for oil and natural gas. Further, state and local governments may pursue litigation against producers for damages allegedly resulting from climate change, similar to the lawsuits filed by the cities of San Francisco and Oakland, California, in September 2017 against Chevron Corp., ConocoPhillips, Co., ExxonMobil Corp., Royal Dutch Shell Plc and BP p.l.c.. QEP's ability to access and develop new oil and gas reserves may also be restricted by climate change regulation, including GHG reporting and regulation.

Congress has previously considered but not adopted proposed legislation aimed at reducing GHG emissions. The EPA has adopted final regulations under the CAA for the measurement and reporting of GHG emitted from certain large facilities and, as discussed above, has adopted additional regulations at 40 C.F.R Part 60, Subparts OOOO and OOOOa to include additional requirements to reduce methane and volatile organic compound emissions from oil and natural gas facilities. As mentioned above, the status of Subpart OOOOa is uncertain given the ongoing litigation, administrative reconsideration and proposed action to stay portions of those rules. Additionally, in June 2014, the United States Supreme Court upheld a portion of EPA’s GHG stationary source permitting program in Utility Air Regulatory Group v. EPA, but also invalidated a portion of it. Upon remand, the EPA is considering how to implement the Court’s decision. The Court’s holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act (CAA) and associated state laws and regulations to which QEP's operations are subject.

In December 2015, over 190 countries, including the U.S., reached an agreement in Paris (COP 21) to reduce global emissions of GHG (the Paris Agreement). The Paris Agreement provides for the cutting of carbon emissions every five years, beginning in 2023, and sets a goal of keeping global warming to a maximum limit of two degrees Celsius and a target limit of 1.5 degrees Celsius greater than pre-industrial levels. In June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement. Withdrawal will take a few years to implement due to the Paris Agreement’s legal structure and language. The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic regulations.

In addition, in several of the states in which QEP operates the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities. Following the initiation of the United States' withdrawal from the Paris Agreement, state and local regulation efforts are expected to increase. Any local or state success in reducing carbon emissions could adversely impact our business by limiting our ability to develop new oil and gas reserves.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in precipitation and extreme weather events. In addition, warmer winters as a result of global warming could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are exacerbated by climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate. Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various species and wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened and endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse effect on our ability to develop and produce our reserves.

Current federal regulations under the National Environmental Policy Act (NEPA) restrict activities during certain times of the year on significant portions of QEP leasehold due to wildlife activity and/or habitat. QEP has worked with federal and state officials in Wyoming to obtain authorization for limited winter drilling activities and has developed measures, such as drilling multiple wells from a single pad location, to minimize the impact of its activities on wildlife and wildlife habitat in its operations on federal lands. Many of QEP's operations are subject to the requirements of NEPA, and are therefore evaluated under NEPA for their direct, indirect and cumulative environmental impacts. This is done in Environmental Assessments or Environmental Impact Statements prepared for a lead agency under Council on Environmental Quality and other agency regulations, usually for the BLM in the areas where QEP operates currently. For example, the Department of Interior’s Fish and Wildlife Service (FWS) plans to issue a proposed rule on whether to list the Lesser Prairie-Chicken as an endangered species. The Lesser Prairie-Chicken is a grouse species native to Texas including parts of the Permian Basin.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be classified as proved reserves if they relate to wells scheduled to be drilled within five years after the date of booking. SEC rules require that, subject to limited exceptions, proved undeveloped (PUD) reserves may only be classified as proved reserves if they are from wells scheduled to be drilled within five years after the date of booking. QEP may be required to write down its PUD reserves if it is not successful in drilling PUD wells within the required five-year time frame. Recovery of PUD reserves requires the expenditure of significant capital and successful drilling operations. At December 31, 2016, approximately 51% of our estimated proved reserves were PUD reserves. These reserve estimates reflect our plans to make significant capital expenditures to convert our PUDs into proved developed reserves, requiring an estimated $3.1 billion during the five years ending December 31, 2021. The estimated development costs may not be accurate; timing to incur such costs may change; development may not occur as scheduled; and results may not be as estimated.

Multi-well pad drilling may result in volatility in QEP operating results and delay conversion of PUD reserves. QEP utilizes multi-well pad drilling where practical. For example, in the Permian Basin, QEP utilizes “tank-style” development, in which we drill and complete all wells in a given "tank" before any individual well is turned to production. Wells drilled on a pad are not brought into production until all wells on the pad are drilled and cased and the drilling rig is moved from the location. In addition, existing wells that offset newly drilled wells may be temporarily shut-in during the drilling and completion process. As a result, multi-well pad drilling delays the completion of wells and the commencement of production, which may cause volatility in QEP's quarterly operating results. Existing wells that offset new wells being completed by QEP or offset operators may also need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following repurchases of QEP shares were made by QEP in association with vested restricted share awards withheld for
taxes.

Period	Total shares purchased[1]	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Remaining dollar amount that may be purchased under the plans or programs
July 1, 2017 - July 31, 2017	—	$ —	—	$ —
August 1, 2017 - August 31, 2017	—	$ —	—	$ —
September 1, 2017 - September 30, 2017	48,769	$ 7.98	—	$ —

(1) All of the 48,769 shares purchased during the three-month period ended September 30, 2017, were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting of restricted share grants.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

Effective October 23, 2017, the Board of Directors (the "Board") of QEP approved and adopted the Amended and Restated Bylaws of the Company (the "Bylaws"), amending certain provisions of the Company's existing bylaws.

The Bylaws revise the advance notice disclosure requirements to require the stockholder proposing business or nominating directors to provide information about the stockholder's ownership of securities in the Company (including ownership of derivative securities) and material litigation, relationships and interests in material agreements with or involving the Company. Further, the Bylaws require the stockholder to provide additional information regarding any candidate the stockholder proposes to nominate for election as a director, including all information with respect to such nominee that would be required to be set forth in a stockholder's notice if such nominee were a stockholder delivering such notice and a description of any direct or indirect material interest in any material contract or agreement between or among the nominating stockholder and each nominee or his or her respective associates. The Bylaws also require the stockholder to provide information regarding the proposed business and any related agreements between the stockholder and any other beneficial holder.

The Bylaws also include certain technical, conforming, modernizing and clarifying changes.

The foregoing description of the amendments is qualified in its entirety by reference to the full text of the Bylaws, a copy of which is attached as Exhibit 3.2 to this Quarterly Report on Form 10-Q and incorporated herein by reference.

ITEM 6. EXHIBITS

The following exhibits are being filed as part of this report:

Exhibit No.	Exhibits
3.1	Amended and Restated Certificate of Incorporation dated May 17, 2017 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 18, 2017).
3.2*	Amended and Restated Bylaws, effective October 23, 2017.
10.1*	Purchase and Sale Agreement, dated July 24, 2017, by and between QEP Energy Company, as seller, and Pinedale Energy Partners, LLC, as buyer (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by the Company with the Securities and Exchange Commission on July 25, 2017); as amended by the First Amendment to Purchase and Sale Agreement, dated September 20, 2017, by and among QEP Energy Company, Pinedale Energy Partners, LLC and Pinedale Energy Partners Operating LLC.
10.2	Purchase and Sale Agreement, dated July 26, 2017, by and between QEP Energy Company, as buyer, and JM Cox Resources, L.P., Alpine Oil Company, and Kelly Cox, collectively as sellers (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on July 26, 2017).
10.3*+	Separation Agreement, dated as of September 15, 2017, between the Company and Matthew T. Thompson.
10.4*+	Amendment to Long Term Incentive Agreements, dated as of September 15, 2017, between the Company and Matthew T. Thompson.
31.1	Certification signed by Charles B. Stanley, QEP Resources, Inc.'s Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification signed by Richard J. Doleshek, QEP Resources, Inc.'s Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification signed by Charles B. Stanley and Richard J. Doleshek, QEP Resources, Inc.'s Chief Executive Officer and Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

+ Indicates a management contract or compensatory plan or arrangement.

* Filed herewith

** These interactive data files are furnished and deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Act of 1934, as amended, and otherwise are not subject to liability under those sections.

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.

	QEP RESOURCES, INC. (Registrant)
October 25, 2017	/s/ Charles B. Stanley Charles B. Stanley, Chairman, President and Chief Executive Officer
October 25, 2017	/s/ Richard J. Doleshek Richard J. Doleshek, Executive Vice President and Chief Financial Officer