RSP Permian, Inc.
Form 10-Q
November 06, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark one)

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

or

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: 001-36264

RSP Permian, Inc.
(Exact name of registrant as specified in its charter)

Delaware State or other jurisdiction of incorporation or organization	90-1022997 (I.R.S. Employer Identification Number)
3141 Hood Street, Suite 500 Dallas, Texas (Address of principal executive offices)	75219 (Zip code)

(214) 252-2700

(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Registration S-T (§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, or a smaller reporting company, or an emerging growth company. See definition of “large accelerated filer,” “accelerated filer” and “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	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

The registrant had 158,599,281 shares of common stock outstanding at November 3, 2017.

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GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

The following are abbreviations and definitions of certain terms used in this Quarterly Report on Form 10-Q:

"Bbl." A standard barrel containing 42 U.S. gallons.

"Boe." One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

"Boe/d." One Boe per day.

"Btu." One British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

"Completion." The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Development project." A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

"Differential." An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

"Drilled but uncompleted well." A well that has been drilled but has not undergone the final steps of hydraulic fracturing and procedures necessary to place the well on production.

"Dry hole" or "dry well." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Economically producible." The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"Exploratory well." A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock that has distinct characteristics that differs from nearby rock.

"Horizontal drilling." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

“MBbl.” One thousand barrels.

“MBoe.” One thousand Boe.

“Mcf.” One thousand cubic feet.

“MMBtu.” One million British thermal units.

"MMcf." One million cubic feet.

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“Net acres.” The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

“NGLs.” Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

“NYMEX.” The New York Mercantile Exchange.

“Operator.” The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

“Plugging.” The sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface.

“Prospect.” A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

“Proved developed reserves.” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“Proved reserves.” The estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

“Realized price.” The cash market price less all expected quality, transportation and demand adjustments.

“Recompletion.” The process of re-entering an existing wellbore that is either producing or not producing and completing another formation in an attempt to establish or increase existing production.

“Reserves.” Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

“Reservoir.” A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

“SEC.” The United States Securities and Exchange Commission.

“Spot market price.” The cash market price without reduction for expected quality, transportation and demand adjustments.

“Undeveloped acreage.” Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

“Wellbore.” The hole drilled by the bit that is equipped for oil and natural gas production on a completed well. Also called well or borehole.

“Working interest.” The right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

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“WTI.” West Texas Intermediate, a type of crude oil used as a benchmark in oil pricing and the underlying commodity of NYMEX oil futures contracts.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements in this Quarterly Report on Form 10-Q, including, without limitation, statements containing the words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “will,” “may,” “should,” “would,” “could” or other similar and statements regarding the Company’s business strategy and plans, constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, 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 (the “Exchange Act”). These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. We cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important known factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, the actual and expected volatility of commodity prices, product supply and demand, competition, access to and cost of capital, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the ability to assimilate acquisitions into our operations, the assumptions underlying production forecasts, the quality of technical data, environmental and weather risks, including the possible impacts of climate change, the ability to obtain environmental and other permits and the timing thereof, government regulation or action, the costs and results of drilling and operations, the availability of equipment, services, resources and personnel required to complete our operating activities, access to and availability of transportation, processing and refining facilities, the financial strength of counterparties to our credit facility and derivative contracts and the purchasers of our production and service providers to us, and acts of war or terrorism. For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see “Part I, Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2016 and our other filings with the SEC.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.
RSP PERMIAN, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)
(In thousands, except share data)

	September 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$46,474	$690,776
Accounts receivable	107,574	73,671
Derivative instruments	14,742	11,815
Total current assets	168,790	776,262
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	6,671,155	4,645,781
Accumulated depletion	(717,958)	(554,419)
Total oil and natural gas properties, net	5,953,197	4,091,362
Other property and equipment, net	57,037	38,273
Total property, plant and equipment	6,010,234	4,129,635
OTHER LONG-TERM ASSETS		
Derivative instruments	5,361	—
Restricted cash	—	152
Other long-term assets	52,450	90,378
Total other long-term assets	57,811	90,530
TOTAL ASSETS	$6,236,835	$4,996,427
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$52,769	$14,074
Accrued expenses	98,372	53,192
Interest payable	29,403	12,142
Derivative instruments	19,719	28,861
Total current liabilities	200,263	108,269
LONG-TERM LIABILITIES		
Other long-term liabilities	12,955	15,916
Derivative instruments	4,169	—
Long-term debt	1,478,500	1,132,275
Deferred taxes	363,764	322,655
Total long-term liabilities	1,859,388	1,470,846
Total liabilities	2,059,651	1,579,115
STOCKHOLDERS' EQUITY		
Common stock, $.01 par value; 300,000,000 shares authorized, 158,576,333 shares issued and outstanding at September 30, 2017; 141,923,591 shares issued and outstanding at December 31, 2016	1,586	1,419
Additional paid-in capital	4,124,271	3,455,916
Accumulated earnings (deficit)	51,327	(40,023)
Total stockholders' equity	4,177,184	3,417,312

TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$6,236,835	$4,996,427

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands, except per share data)

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
REVENUES				
Oil sales	$174,624	$84,722	$486,656	$211,212
Natural gas sales	9,661	3,901	26,898	8,841
NGL sales	17,369	4,998	41,131	10,869
Total revenues	201,654	93,621	554,685	230,922
OPERATING EXPENSES				
Lease operating expenses	33,385	14,174	87,688	41,359
Production and ad valorem taxes	13,281	5,872	32,892	14,985
Depreciation, depletion and amortization	73,408	50,022	202,552	141,877
Asset retirement obligation accretion	151	118	454	354
Impairment of unproved properties	705	971	6,142	4,322
Exploration expenses	1,497	359	6,946	828
General and administrative expenses	12,120	8,857	36,175	25,997
Acquisition costs	30	—	4,483	—
Total operating expenses	134,577	80,373	377,332	229,722
OPERATING INCOME	67,077	13,248	177,353	1,200
OTHER INCOME (EXPENSE)				
Other income, net	1,106	310	2,415	587
Net gain (loss) on derivative instruments	(21,626)	(2,934)	7,689	(6,222)
Interest expense	(21,553)	(13,146)	(60,285)	(39,041)
Total other income (expense)	(42,073)	(15,770)	(50,181)	(44,676)
INCOME (LOSS) BEFORE TAXES	25,004	(2,522)	127,172	(43,476)
INCOME TAX (EXPENSE) BENEFIT	(3,678)	3,507	(35,822)	17,242
NET INCOME (LOSS)	$21,326	$985	$91,350	$(26,234)
Income (loss) per common share:				
Basic	$0.14	$0.01	$0.59	$(0.26)
Diluted	$0.14	$0.01	$0.59	$(0.26)
Weighted average shares outstanding:				
Basic	156,864	100,234	153,258	100,161
Diluted	157,837	100,234	154,278	100,161

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(Unaudited)
(In thousands)

	Issued Shares of Common Stock	Common Stock	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total Stockholders' Equity
BALANCE AT DECEMBER 31, 2016	141,924	$ 1,419	$ 3,455,916	$ (40,023)	$ 3,417,312
Shares of common stock issued for acquisition	16,020	160	663,694	—	663,854
Equity issuance costs	—	—	(349)	—	(349)
Repurchase and retirement of common stock	(190)	(1)	(7,710)	—	(7,711)
Equity-based compensation	824	8	12,720	—	12,728
Net income	—	—	—	91,350	91,350
BALANCE AT SEPTEMBER 30, 2017	158,578	$ 1,586	$ 4,124,271	$ 51,327	$ 4,177,184

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$91,350	$(26,234)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	202,552	141,877
Asset retirement obligation accretion	454	354
Impairment of unproved properties	6,142	4,322
Equity-based compensation	12,728	10,549
Amortization of loan fees	3,106	1,969
Deferred income taxes	41,110	(9,873)
Other	(413)	230
Net (gain) loss on derivative instruments	(7,689)	6,222
Net cash (payments) receipts from settled derivatives	(5,770)	9,963
Changes in operating assets and liabilities:		
Accounts receivable	(33,903)	(29,719)
Other assets	(21,080)	9,225
Accounts payable	38,893	(13,117)
Accrued expenses	141	2,424
Interest payable	17,261	11,573
Net cash provided by operating activities	344,882	119,765
CASH FLOWS FROM INVESTING ACTIVITIES		
Development of oil and natural gas properties	(448,408)	(207,437)
Acquisitions of oil and natural gas properties	(856,234)	(62,430)
Acquisition deposit held in escrow	(1,812)	—
Acquisition of infrastructure assets	(19,156)	(1,750)
Proceeds from sale of assets	1,527	—
Other	(1,497)	(800)
Net cash used in investing activities	(1,325,580)	(272,417)
CASH FLOWS FROM FINANCING ACTIVITIES		
Payment of deferred loan costs	(544)	—
Borrowings under long-term debt	345,000	35,000
Payments of equity issuance costs	(349)	—
Repurchase and retirement of common stock	(7,711)	(2,713)
Net cash provided by financing activities	336,396	32,287
NET CHANGE IN CASH	(644,302)	(120,365)
CASH AT BEGINNING OF PERIOD	690,776	142,741
CASH AT END OF PERIOD	$46,474	$22,376
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash paid for interest	$39,919	$25,463
Cash paid for taxes	$—	$2,000
NON-CASH ACTIVITIES		
Asset retirement obligation acquired	$822	$342

Change in accrued capital expenditures	$39,787	$(7,918)
Common stock issued for oil and gas properties	$663,854	$—
Release of deposit held in escrow for oil and gas properties	$64,122	$—

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

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NOTE 1—NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Organization and Description of the Business

RSP Permian, Inc., a Delaware corporation ("RSP Inc.," the "Company," "we," "our," or "us"), is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. The vast majority of the Company's acreage is located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin, both sub-basins of the Permian Basin. The Midland Basin properties are primarily in the adjacent counties of Midland, Martin, Andrews, Ector and Glasscock. The Delaware Basin properties are in Loving and Winkler counties. The Company's common stock is listed and traded on the NYSE under the ticker symbol "RSPP."

Basis of Presentation

These consolidated financial statements have been prepared by the Company pursuant to the rules and regulations of the SEC. They reflect all adjustments that are, in the opinion of management, necessary for a fair presentation of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. The consolidated financial statements of the Company include the accounts of the Company and its wholly owned subsidiaries. Certain information, accounting policies, and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to such rules and regulations, although the Company believes the disclosures are adequate to make the information presented not misleading. The financial statements in this Quarterly Report on Form 10–Q should be read together with the financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016, which contains a complete summary of the Company's significant accounting policies and disclosures.

Subsequent Events

The Company has evaluated events that occurred subsequent to September 30, 2017 in preparing its consolidated financial statements. The Company determined there were no events, other than as described below, that required disclosure or recognition in these financial statements.

On October 19, 2017, the Company entered into a first amendment to our credit agreement, which, (a) increased the borrowing base to $1.5 billion from $1.1 billion, (b) maintained our elected commitment at $900 million and (c) decreased the applicable margins for interest rates applicable to amounts outstanding under the revolving credit facility from a range of 200 to 300 basis points above the applicable reference rate for Eurodollar loans and 100 to 200 basis points above the applicable reference rate for alternate base rate loans to ranges of 150 to 250 basis points for Eurodollar loans and 50 to 150 basis points for alternate base rate loans.

In November 2017, the Company exchanged $450.0 million of the 5.25% senior unsecured notes for registered notes with the same terms.

During the fourth quarter of 2017, the Company has entered into derivative contracts covering 2.7 million barrels of crude oil production beginning in the first quarter of 2018 through the fourth quarter of 2018, and now has derivative contracts covering 9.4 million barrels of 2018 oil volumes. See Note 4 for a summary of derivative positions entered into subsequent to September 30, 2017.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities in the financial statements and accompanying notes. Although management believes these estimates are reasonable, actual results could differ from these estimates. Changes in estimates are recorded prospectively. Significant assumptions are required in the valuation of proved oil and natural gas reserves that may affect the amount at which oil and natural gas properties are recorded. Estimation of asset retirement obligations ("AROs") and valuations of derivative instruments also require significant assumptions. It is possible that these estimates could be revised at future dates and these revisions could be material. Depletion of oil and natural gas properties is determined using estimates of proved oil and natural gas reserves. There are numerous

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uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price estimates. It is possible that these estimates could be revised at future dates and such revisions could be material.

Reclassifications

Certain reclassifications have been made to prior periods to conform to current period presentation. None of these reclassifications impacted previously reported equity, cash flows, or operating income amounts.

Accounts Receivable

	As of September 30, 2017	As of December 31, 2016
	(In thousands)	
Sale of oil, natural gas liquids and natural gas	$89,910	$ 54,422
Joint interest owners	17,628	16,681
Federal income tax receivable	36	2,568
Total accounts receivable	$107,574	$ 73,671

Accounts receivable, which are primarily from the sale of oil, NGLs and natural gas, are accrued based on estimates of the volumetric sales and prices the Company believes it will receive. In addition, settled but uncollected derivative contracts, receivables related to joint interest billings and income tax receivables are included in accounts receivable. The Company routinely reviews outstanding balances, assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. The need for an allowance is determined based upon reviews of individual accounts, historical losses, existing economic conditions and other pertinent factors. Bad debt expense was zero for each of the three and nine months ended September 30, 2017 and 2016, respectively.

Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for its oil and natural gas exploration and production activities. Costs incurred by the Company related to the acquisition of oil and natural gas properties and the cost of drilling development wells and successful exploratory wells are capitalized, while the costs of unsuccessful exploratory wells are expensed when determined to be unsuccessful.

The Company may capitalize interest on expenditures for significant exploration and development projects that last more than six months, while activities are in progress to bring the assets to their intended use. The Company has not capitalized any interest as projects generally lasted less than six months. Costs incurred to maintain wells and related equipment, lease and well operating costs and other exploration costs are expensed as incurred.

Capitalized acquisition costs attributable to proved oil and natural gas properties and leasehold costs are depleted on a field level, based on proved reserves, using the unit-of-production method. Capitalized exploration well costs and development costs, including AROs, are depleted on a field level, based on proved developed reserves. For the three months ended September 30, 2017 and 2016, depletion expense for oil and natural gas property was $72.7 million and $49.6 million, respectively. For the nine months ended September 30, 2017 and 2016, depletion expense for oil and natural gas property was $200.5 million and $140.7 million, respectively.

Depletion expense is included in depreciation, depletion and amortization in the accompanying consolidated statements of operations.

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The Company's oil and natural gas properties as of September 30, 2017 and December 31, 2016 consisted of the following:

	September 30, 2017	December 31, 2016
	(In thousands)	
Proved oil and natural gas properties	$3,695,840	$2,811,853
Unproved oil and natural gas properties	2,975,315	1,833,928
Total oil and natural gas properties	6,671,155	4,645,781
Less: Accumulated depletion	(717,958)	(554,419)
Total oil and natural gas properties, net	$5,953,197	$4,091,362

In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the anticipated reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. As of September 30, 2017 and December 31, 2016, there were no costs capitalized in connection with exploratory wells in progress.

Capitalized costs are evaluated for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. To determine if a field is impaired, the Company compares the carrying value of the field to the undiscounted future net cash flows by applying estimates of future oil, NGLs and natural gas prices to the estimated future production of oil and natural gas reserves over the economic life of the property and deducting future costs. Future net cash flows are based upon our reservoir engineers' estimates of proved reserves and risk-adjusted probable reserves.

For a property determined to be impaired, an impairment loss equal to the difference between the property's carrying value and its estimated fair value is recognized. Fair value, on a field basis, is estimated to be the present value of the aforementioned expected future net cash flows. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future net cash flows and fair value. No impairment of proved property was recorded for the nine months ended September 30, 2017 or 2016. The calculation of expected future net cash flows in impairment evaluations are mainly based on estimates of future oil and natural gas prices, proved reserves and risk-adjusted probable reserve quantities, and estimates of future production and capital costs associated with our proved and risk-adjusted reserves. The Company's estimates for future oil and natural gas prices used in the impairment evaluations are based on observable prices for the next three years, and then held constant for the remaining lives of the properties. If the prices used to assess our oil and natural gas properties for impairment were 15% lower than the prices we used for such analysis, holding all other variables constant, we would not have expected to record any material impairment to our proved oil and natural gas properties. However, it is reasonably possible that oil and natural gas prices used in future impairment evaluations may decline, which could result in the need to impair the carrying value of the Company's proved properties.

Unproved property costs and related leasehold expirations are assessed quarterly for potential impairment and when industry conditions dictate an impairment may be possible. For the nine months ended September 30, 2017 and 2016, impairment expense of unproved property was $6.1 million and $4.3 million, respectively, which primarily related to management's expectation that certain leasehold interests would expire and not be renewed, along with certain leasehold interests that may expire or could otherwise be disposed of in the future.

Asset Retirement Obligation

The Company records AROs related to the retirement of long-lived assets at the time a legal obligation is incurred and the liability can be reasonably estimated. AROs are recorded as long-term liabilities with a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future down-hole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of the surface acreage to a condition similar to that existing before oil and natural gas extraction began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted

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rate. If the estimated ARO changes, an adjustment is recorded to both the ARO liability and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

After recording these amounts, the ARO liability is accreted to its future estimated value using the same assumed credit adjusted rate and the associated capitalized costs are depreciated on a unit-of-production basis.

The ARO liability consisted of the following for the period indicated:

	Nine Months Ended September 30, 2017
	(In thousands)
Asset retirement obligation at beginning of period	$ 10,659
Liabilities incurred or assumed	2,031
Liabilities settled	(193)
Accretion expense	454
Asset retirement obligation at end of period	$ 12,951

Income Taxes

The following is an analysis of the Company's consolidated income tax (expense) benefit for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
			(In thousands)	
Current (1)	$7,423	$7,369	$5,288	$7,369
Deferred (1)	(11,101)	(3,862)	(41,110)	9,873
Income Tax (Expense) Benefit	$(3,678)	$3,507	$(35,822)	$17,242

(1) In the third quarter of 2017 and 2016, the Company recorded discrete deferred tax benefits associated with research and development credit claims, net of uncertain tax positions, of $5.3 million and $2.4 million, respectively.

Deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of enacted tax laws. Tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The Company's policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At December 31, 2016, the Company had a long-term tax payable related to uncertain tax positions totaling $5.3 million. This amount was recorded in other long-term liabilities on the consolidated balance sheet. In the third quarter of 2017, the Company decreased the liability associated with uncertain tax positions to zero due to return to provision adjustments, which resulted in a current tax benefit offset by deferred tax expense with no impact to total tax expense.

The Company's adoption of ASU 2016-09 in the first quarter of 2017 using the modified retrospective approach resulted in a decrease to deferred tax liability and a corresponding adjustment to accumulated deficit of $0.6 million as of December 31, 2016. Additional tax deductions during the nine months ended September 30, 2017 from stock compensation under the guidance of ASU 2016-09 resulted in a reduction to income tax expense of $4.1 million.

The Company’s U.S. federal income tax returns for 2013 and beyond, and its Texas franchise tax returns for 2012 and beyond, remain subject to examination by the taxing authorities. No other jurisdiction’s returns are significant to the Company’s financial position.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2014-09, “Revenue from Contracts with Customers (Topic 606),” which provides a comprehensive revenue recognition standard for contracts with customers that supersedes current revenue recognition guidance including industry specific guidance. An entity is required to apply ASU 2014-09 for annual and interim reporting periods beginning after December 15, 2017. An entity can apply ASU 2014-09 using either a full retrospective method, meaning the standard is applied to all of the periods presented, or a

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modified retrospective method, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. The Company has selected the modified retrospective method and is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements; however, it has not identified any revenue stream that would be materially impacted and does not expect the adoption of this standard to have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)," which requires all lease transactions (with expected lease terms in excess of 12 months) to be recognized on the balance sheet as lease assets and lease liabilities. Public entities are required to apply ASU 2016-02 for annual and interim reporting periods beginning after December 15, 2018 with early adoption permitted. The Company is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements.

In March 2016, the FASB issued ASU 2016-09, "Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting," which simplifies several aspects of the accounting for share-based payment award transactions. These simplifications include the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The Company adopted this guidance in the first quarter of 2017 using the modified retrospective approach. Accordingly, the deferred tax liability at December 31, 2016 was reduced by $0.6 million with a corresponding adjustment to accumulated deficit in the consolidated balance sheet.

NOTE 3—ACQUISITIONS OF OIL AND NATURAL GAS PROPERTY INTERESTS

Silver Hill Acquisitions

On October 13, 2016, the Company entered into definitive agreements to acquire 100% of Silver Hill Energy Partners, LLC ("SHEP I") and Silver Hill E&P II, LLC ("SHEP II", and together with SHEP I, "Silver Hill") for an aggregate purchase price of $1.25 billion of cash and 31.0 million shares of RSP Inc. common stock in aggregate. Silver Hill was comprised of two privately-held entities that collectively owned oil and gas producing properties and undeveloped acreage in Loving and Winkler counties in Texas and owned approximately 40,100 net acres. Silver Hill's highly contiguous acreage position in the core of the Delaware Basin was complementary to the Company's asset base and the acquisition creates substantial scale from a production and acreage standpoint.

The SHEP I acquisition closed on November 28, 2016, with cash consideration of $604 million, including assumed debt obligations which were repaid, before purchase price adjustments, and approximately 15.0 million shares of RSP Inc. common stock. Substantially all of the value of the transaction was related to the value of the oil and gas assets acquired with minimal value ascribed to other assets.

The SHEP II acquisition closed on March 1, 2017, with cash consideration of $646 million, before purchase price adjustments, and approximately 16.0 million shares of RSP Inc. common stock. A summary of the consideration transferred and the fair value of assets and liabilities acquired is as follows (in thousands, except shares):

Value of the Company's common stock issued in the SHEP II acquisition (1)	$663,854
Cash paid to sellers in the SHEP II acquisition (including deposit)	641,577
Total consideration for the assets contributed in the SHEP II acquisition	$1,305,431
Fair value of oil and natural gas properties (2)	1,308,177
Asset retirement obligation	(822)
Assumption of other liabilities	(1,924)
Total net assets acquired	$1,305,431

(1) The Company issued 16,019,638 shares of common stock at $41.44 per share (closing price) on March 1, 2017.
(2) Approximately 77% of the acquisition date fair value of oil and natural gas properties was recorded as unproved property.

The acquisition of SHEP II was accounted for using the acquisition method of accounting with the Company as the acquirer. Under the acquisition method of accounting, the Company recorded all assets acquired and liabilities assumed at their respective acquisition date fair values at the closing date of the acquisition. The fair values of the assets acquired and liabilities assumed are based on a detailed analysis, using industry accepted methods of estimating the current fair value as described below.

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For the SHEP II acquisition, substantially all of the value of the transaction was related to the value of the oil and gas assets acquired with no value ascribed to other assets. The Company used two valuation methods in its determination of fair value for the oil and gas properties: the discounted cash flow analysis and comparable transaction analysis. The significant assumptions included in the discounted cash flow analysis include commodity price assumptions, costs and capital outlay to develop the acquired properties, pricing differentials, reserve risking, and discount rates. NYMEX strip pricing at the SHEP II acquisition date of March 1, 2017, less applicable pricing differentials, was utilized in the discounted cash flow analysis. Risking levels in the discounted cash flow analysis are determined based on a variety of factors, such as existing well performance, offset production and analogue wells. Discount rates used in the discounted cash flow analysis were determined using the estimated weighted average cost of capital for the Company, discount rates published in third party publications, as well as industry knowledge and experience. The comparable transaction analysis was performed to establish a range of fair values for similarly-situated oil and gas properties that were recently bought or sold in arms-length, observable market transactions. The range of value observed from the Company’s analysis of recent market transactions and the fair value calculation via the discounted cash flow method was used as a basis to determine fair value of the assets. The Company’s fair value conclusion indicated that the discounted cash flow method valuation is substantially in the same range as the comparable transactions reviewed, when considering the comparable transactions on a median or average basis. Other current liabilities assumed in the SHEP II acquisition, which related to revenues held in suspense, were carried over at historical carrying values because the liabilities are short term in nature and their carrying values are estimated to represent the best estimate of fair value.

Revenues and earnings of SHEP II recognized in 2017 subsequent to the acquisition date were $46.7 million and $15.8 million, respectively. The Company recognized $4.5 million of expenses related to the SHEP II acquisition in the first quarter of 2017, which are recorded in acquisition costs on the consolidated statement of operations.

Pro Forma Results

The Company’s summary pro forma results for the three and nine months ended September 30, 2017 and 2016 were derived from the actual results of the Company adjusted to reflect the SHEP II acquisition, as if such transaction had occurred on January 1, 2016. The below information reflects pro forma adjustments for the issuance of common stock to the sellers of SHEP II along with common stock issued in the October 2016 public offering that funded the cash portion of the SHEP II acquisition. Additional pro forma adjustments, based on available information and certain assumptions, include (i) the depletion of SHEP II fair-valued proved oil and gas properties, and (ii) the estimated tax impacts of the pro forma adjustments. Pro forma earnings for the three and nine months ended September 30, 2017 were adjusted to exclude zero and $4.5 million, respectively, of related acquisition costs incurred by the Company.

The pro forma financial information included below does not give effect to certain acquisitions that were immaterial to the Company's actual and pro forma results for the periods reflected below and does not make any adjustments for non-recurring expenses associated with the SHEP II acquisition, except for the acquisition costs described above.

The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of expected future results of operations.

	Three Months Ended September 30, 2017		Three Months Ended September 30, 2016	
	Actual	Pro Forma	Actual	Pro Forma

	(In thousands, except per share data)		(In thousands, except per share data)	
Revenues	$ 201,654	$ 201,654	$ 93,621	$ 111,974
Net income	$ 21,326	$ 21,326	$ 985	$ 915
Net income per share:				
Basic	$ 0.14	$ 0.14	$ 0.01	$ 0.01
Diluted	$ 0.14	$ 0.14	$ 0.01	$ 0.01

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	Nine Months Ended September 30, 2017		Nine Months Ended September 30, 2016	
	Actual	Pro Forma	Actual	Pro Forma
	(In thousands, except per share data)		(In thousands, except per share data)	
Revenues	$ 554,685	$ 573,404	$ 230,922	$ 266,950
Net income (loss)	$ 91,350	$ 99,810	$ (26,234)	$ (33,889)
Net income (loss) per share:				
Basic	$ 0.59	$ 0.65	$ (0.26)	$ (0.34)
Diluted	$ 0.59	$ 0.65	$ (0.26)	$ (0.34)

Other Acquisitions

During the third quarter of 2017, the Company closed on two acquisitions of undeveloped acreage and additional mineral interests in the Delaware Basin for an aggregate purchase price of approximately $227.9 million, before purchase price adjustments. These acquisitions were funded with borrowings under our revolving credit facility.

In addition to the acquisitions discussed above, in the first nine months of 2017, the Company closed on bolt-on acquisitions of mostly undeveloped acreage for an aggregate total purchase price of approximately $37.2 million. The acquisitions included additional working interests in properties where the Company owned existing interests as well as other properties in the Company's core areas. These acquisitions were funded with cash on hand and borrowings under our revolving credit facility.

On January 2, 2017, the Company closed on the acquisition of water infrastructure assets from Lone Wolf Resources and related entities for an aggregate total purchase price of $18.8 million, before purchase price adjustments. The acquisition was funded with cash on hand.

NOTE 4—DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments

The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price risk inherent in its crude oil and natural gas production. These may include collar contracts, swaps, deferred premium put options and other related derivative structures. The derivative instruments are recorded at fair value on the consolidated balance sheets and any gains and losses are recognized in current period earnings.

Each collar transaction has an established price floor and ceiling, and certain collar transactions also include a short put as well. When the settlement price is below the price floor established by these collars, the Company receives an amount from its counterparty equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume. When the settlement price is below the short put price, the Company pays its counterparty an amount equal to the difference between the settlement price and the short put price multiplied by the hedged contract volume. Cumulatively, when the settlement price is below the short put price, the Company would receive from its counterparty an amount equal to the difference of the price floor and the short put price multiplied by the hedged contract volume.

Each deferred premium put option has an established floor price. When the settlement price is below the floor price, the Company receives the difference between the floor price and the settlement price multiplied by the hedged contract volume less the cost of the premium for the option. When the settlement price is at or above the floor price, the Company receives no proceeds and pays the cost of the premium for the option. In either case, whether the settlement price is below or above the floor price, the Company pays the premium for the option at the expiration of the option.

Each swap transaction has an established fixed price. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

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The following table summarizes all commodity derivative positions as of September 30, 2017:

	Contracts expiring in the period ending:				
	December 31, 2017	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
Crude Oil Three-Way Collars:					
Notional volume (Bbl)	552,000	2,219,000	1,941,000	1,319,000	1,227,000
Weighted average ceiling price ($/Bbl)(1)	$54.10	$ 58.81	$ 59.07	$ 60.56	$ 60.96
Weighted average floor price ($/Bbl)(1)	$45.00	$ 46.96	$ 47.11	$ 47.79	$ 48.00
Weighted average short put price ($/Bbl)(1)	$35.00	$ 36.96	$ 37.11	$ 37.79	$ 38.00
Crude Oil Costless Collars:					
Notional volume (Bbl)	1,150,000				
Weighted average ceiling price ($/Bbl)(1)	$60.05				
Weighted average floor price ($/Bbl)(1)	$45.00				
Crude Oil Swaps:					
Notional volume (Bbl)	552,000				
Weighted average swap price ($/Bbl)(1)	$48.95				
Crude Oil Deferred Premium Puts:					
Notional volume (Bbl)	920,000				
Weighted average floor price ($/Bbl)(1)	$48.50				
Weighted average deferred premium ($/Bbl) (2)	$(4.00)				
Mid-Cush Differential (Basis) Swaps:					
Notional volume (Bbl)	1,104,000	1,800,000	1,820,000	1,840,000	1,840,000
Weighted average swap price ($/Bbl)(4)	$(0.63)	$ (0.62)	$ (0.62)	$ (0.62)	$ (0.62)
Natural Gas Costless Collars:					
Notional volume (MMBtu)	2,545,000				
Weighted average ceiling price ($/MMbtu)(3)	$3.86				
Weighted average floor price ($/MMbtu)(3)	$3.00				

(1) The crude oil derivative contracts are settled based on the arithmetic average of the closing settlement price for the front month contract NYMEX price of West Texas Intermediate Light Sweet Crude during the relevant period.
(2) The deferred premium is not paid until the expiration date, aligning cash inflows and outflows with the settlement of the derivative contract.
(3) The natural gas derivative contracts are settled based on the last trading day's closing price for the front month contract relevant to each period.
(4) The Mid-Cush swap contracts are settled based on the difference in the arithmetic average during the calculation period of WTI MIDLAND ARGUS and WTI ARGUS prices in the Argus Americas Crude publication for the relevant period.

The following table summarizes all commodity derivative positions entered subsequent to September 30, 2017:

Contracts expiring in the period ending:

	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
Crude Oil Costless Collars:				
Notional volume (Bbl)	571,000	516,000	890,000	736,000
Weighted average ceiling price ($/Bbl)(1)	$60.19	$60.20	$ 60.14	$ 60.16
Weighted average floor price ($/Bbl)(1)	$45.00	$45.00	$ 45.00	$ 45.00

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(1) The crude oil derivative contracts are settled based on the arithmetic average of the closing settlement price for the front month contract NYMEX price of West Texas Intermediate Light Sweet Crude during the relevant period.

Derivative Fair Values and Gains (Losses)

The following table presents the fair value of derivative instruments. The Company’s derivatives are presented as separate line items in its consolidated balance sheets as current and noncurrent derivative instrument assets and liabilities based on the expected settlement dates of the instruments. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of the Company’s master netting arrangements. See Note 5 for further discussion related to the fair value of the Company’s derivatives.

	Assets		Liabilities	
	September 30, 2017	December 31, 2016	September 30, 2017	December 31, 2016
	(In thousands)			
Derivative Instruments:				
Current amounts				
Commodity contracts	$14,742	$ 11,815	$19,719	$ 28,861
Noncurrent amounts				
Commodity contracts	$5,361	$ —	$4,169	$ —
Total derivative instruments	$20,103	$ 11,815	$23,888	$ 28,861

Gains and losses on derivatives are reported in the consolidated statements of operations.

The following represents the Company’s reported gains (losses) on derivative instruments for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands)		(In thousands)	
Gain (loss) on derivative instruments:				
Commodity derivative instruments	$(21,626)	$(2,934)	$7,689	$(6,222)
Total	$(21,626)	$(2,934)	$7,689	$(6,222)

Offsetting of Derivative Assets and Liabilities

The following table presents the Company’s gross and net derivative assets and liabilities.

	Gross Amount Presented on Balance Sheet	Netting Adjustments(a)	Net Asset (Liability)
	(In thousands)		
September 30, 2017			
Derivative instrument assets with right of offset or master netting agreements	$20,103	$ (20,103)	$—
Derivative instrument liabilities with right of offset or master netting agreements	$(23,888)	$ 20,103	$(3,785)
December 31, 2016			
Derivative instrument assets with right of offset or master netting agreements	$11,815	$ (11,815)	$—

Derivative instrument liabilities with right of offset or master netting agreements	$(28,861)	$ 11,815	$(17,046)

(a) The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

Credit-Risk Related Contingent Features in Derivatives

None of the Company’s derivative instruments contain credit-risk related contingent features. No amounts of collateral were posted by the Company related to net positions as of September 30, 2017 and December 31, 2016.

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NOTE 5—FAIR VALUE MEASUREMENTS

The book values of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate fair value due to the short-term nature of these instruments. The book value of the Company’s revolving credit facility approximates fair value as the interest rate is variable. At September 30, 2017, the fair value of the Company's 6.625% senior notes was $733.3 million and the fair value of the Company's 5.25% senior notes was $455.1 million. If the Company recorded the 6.625% senior notes at fair value they would be Level 1 in our fair value hierarchy as they are traded in an active market with quoted prices for identical instruments. If the Company recorded the 5.25% senior notes at fair value they would be Level 2 in our fair value hierarchy as these notes have not been registered and do not trade in an active market as of September 30, 2017. The fair value of derivative financial instruments is determined utilizing industry standard models using assumptions and inputs which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors.

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

•Level 1—Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
•Level 2—Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.
•Level 3—Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs that are not corroborated by market data and may reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

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

Fair Value Measurement on a Recurring Basis

The following table presents, by level within the fair value hierarchy, the Company’s assets and liabilities that are measured at fair value on a recurring basis.

	Level 1	Level 2	Level 3	Total fair value
	(In thousands)			
As of September 30, 2017:				
Commodity derivative instruments	$ —	$ (3,785)	$ —	$ (3,785)

Total	$—	$(3,785)	$—	$(3,785)

	Level 1	Level 2	Level 3	Total fair value
	(In thousands)			
As of December 31, 2016:				
Commodity derivative instruments	$—	$(17,046)	$—	$(17,046)
Total	$—	$(17,046)	$—	$(17,046)

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Significant Level 2 assumptions used to measure the fair value of the commodity derivative instruments include implied volatility factors, appropriate risk adjusted discount rates, as well as other relevant data.

Reclassifications of fair value among Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. There were no transfers among Level 1, Level 2 or Level 3 during the nine months ended September 30, 2017 and the year ended December 31, 2016.

Nonfinancial Assets and Liabilities

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and natural gas property acquired include the Company's estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. Additionally, fair value is used to determine the inception value of the Company's AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company's AROs represent a nonrecurring Level 3 measurement.

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

NOTE 6—LONG-TERM DEBT

Long-term debt consists of the following:

	September 30, 2017	December 31, 2016
	(In thousands)	
Revolving credit facility	$345,000	$—
5.25% Senior notes	450,000	450,000
6.625% Senior notes	700,000	700,000
Less: Discount	(1,000)	(1,150)
Less: Debt issuance costs	(15,500)	(16,575)
Total long-term debt	$1,478,500	$1,132,275

Revolving Credit Facility

As of September 30, 2017, the borrowing base under the Company's amended and restated credit agreement was $1.1 billion, with a Company-elected commitment of $900 million, and lender commitments of $2.5 billion. The maturity date of the Company's revolving credit facility is December 19, 2021. The amount available to be borrowed under the revolving credit facility is subject to a borrowing base that is redetermined semiannually each May and November and depends on the volumes of proved oil and natural gas reserves and estimated cash flows from these reserves and commodity hedge positions. As of September 30, 2017, we had $345.0 million in borrowings and $0.4 million of letters of credit outstanding under our revolving credit facility and $554.6 million of borrowing capacity.

On October 19, 2017, the Company entered into a first amendment to our credit agreement, which, (a) increased the borrowing base to $1.5 billion from $1.1 billion, (b) maintained our elected commitment at $900 million and (c) decreased the applicable margins for interest rates applicable to amounts outstanding under the revolving credit facility from a range of 200 to 300 basis points above the applicable reference rate for Eurodollar loans and 100 to 200 basis points above the applicable reference rate for alternate base rate loans to ranges of 150 to 250 basis points for Eurodollar loans and 50 to 150 basis points for alternate base rate loans.

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The Company's revolving credit facility requires it to maintain the following two financial ratios:

•a working capital ratio, which is the ratio of consolidated current assets (includes unused commitments under its revolving credit facility and excludes restricted cash and derivative assets) to consolidated current liabilities (excluding the current portion of long-term debt under the credit facility and derivative liabilities), of not less than 1.0 to 1.0;
•a leverage ratio, which is the ratio of the sum of all of the Company’s debt to the consolidated EBITDAX (as defined in the credit agreement) for the four fiscal quarters then ended, of not greater than 4.25 to 1.0.

The Company’s revolving credit facility also contains restrictive covenants that may limit its ability to, among other things, incur additional indebtedness, make loans to others, make investments, enter into mergers, make or declare dividends, enter into commodity hedges exceeding a specified percentage or its expected production, enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness, incur liens, sell assets or engage in certain other transactions without the prior consent of the lenders.

The Company was in compliance with such covenants and ratios as of September 30, 2017.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. The Company has a choice of borrowing at a Eurodollar rate or at the adjusted base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the quotient of: (i) the LIBOR Rate; divided by (ii) a percentage equal to 100% minus the maximum rate on such date at which the Administrative Agent is required to maintain reserves on “Eurocurrency Liabilities” as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of its borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank’s referenced rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized, plus a commitment fee ranging from 37.5 basis points to 50 basis points charged on the undrawn commitment amount.

Senior Notes Due 2025

On December 27, 2016, the Company issued $450.0 million of 5.25% senior unsecured notes at par through a private placement. The notes will mature on January 15, 2025. The notes are senior unsecured obligations that rank equally with all of our future senior indebtedness, are as a result of being unsecured effectively subordinated in rights to our assets constituting collateral held by all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including indebtedness under our revolving credit facility, and will rank senior to any future subordinated indebtedness of the Company. Interest on these notes is payable semi-annually on January 15 and July 15, commencing on July 15, 2017. On or after January 15, 2020, the Company may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in twelve-month intervals to 100% in 2023 and thereafter. In addition, prior to January 15, 2020, on any one or more occasions, the Company may redeem all or part of the notes at a redemption price of 100% of the principal amount of the notes redeemed, plus an applicable make-whole premium along with accrued and unpaid interest.

The Company incurred approximately $6.4 million of debt issuance costs related to the 2016 note issuance, which are a reduction to “Long-term debt” on the Company’s consolidated balance sheets and will be amortized to interest expense, net, over the life of the notes using the effective interest method. In the event of a change in control of the Company whereby the notes are downgraded, each note holder will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The notes are guaranteed on a senior unsecured basis by each of our consolidated subsidiaries. The subsidiary guarantees are full and unconditional and joint and several, and any subsidiaries of the Company other than the subsidiary guarantors are minor. RSP Inc. does not have independent assets or operations. The terms of the notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. In November 2017, the Company exchanged $450.0 million of the 5.25% senior unsecured notes for registered notes with the same terms. The Company was in compliance with the provisions of the indenture governing the senior unsecured notes as of September 30, 2017.

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Senior Notes Due 2022

On September 26, 2014, the Company issued $500.0 million of 6.625% senior unsecured notes at par through a private placement. On August 10, 2015, the Company issued an additional $200.0 million of these notes at 99.25% of the principal amount through a private placement. The notes will mature on October 1, 2022. The notes are senior unsecured obligations that rank equally with all of our future senior indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowings under our revolving credit facility, and will rank senior to any future subordinated indebtedness of the Company. Interest on these notes is payable semi-annually on April 1 and October 1. After October 1, 2017, the Company may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.969% of principal, declining in twelve-month intervals to 100% in 2020 and thereafter.

The Company incurred approximately $11.3 million of debt issuance costs related to the 2014 note issuance and $2.4 million related to the 2015 note issuance, which are a reduction to “Long-term debt” on the Company’s consolidated balance sheets and will be amortized to interest expense, net, over the life of the notes using the effective interest method. In the event of certain changes in control of the Company, each note holder will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The notes are guaranteed on a senior unsecured basis by each of our consolidated subsidiaries. The subsidiary guarantees are full and unconditional and joint and several, and any subsidiaries of the Company other than the subsidiary guarantors are minor. RSP Inc. does not have independent assets or operations. The terms of the notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. In June 2015, the Company exchanged $500.0 million of these notes for registered notes with the same terms. In March 2016, the Company exchanged an additional $200.0 million of these notes for registered notes with the same terms. The Company was in compliance with the provisions of the indenture governing the senior unsecured notes as of September 30, 2017.

NOTE 7—COMMITMENTS AND CONTINGENCIES

Legal Matters

The Company is party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect, individually or in the aggregate, on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then-current status of the matters.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed as incurred. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory policies and procedures.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed.

Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At both September 30, 2017 and December 31, 2016, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

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Contractual Obligations

For the nine months ended September 30, 2017, the Company had no material changes in its contractual commitments and obligations from amounts listed under "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Requirements and Sources of Liquidity - Contractual Obligations" in our Annual Report on Form 10-K for the year ended December 31, 2016 other than $345.0 million in borrowings under our revolving credit facility, compared to no outstanding borrowings at December 31, 2016.

NOTE 8—EQUITY-BASED COMPENSATION

Equity-based compensation expense, which was recorded in general and administrative expenses, was $4.4 million and $3.3 million for the three months ended September 30, 2017 and 2016, respectively. This equity-based compensation expense was $12.7 million and $10.5 million for the nine months ended September 30, 2017 and 2016, respectively.

Restricted Stock Awards

In connection with the Company's initial public offering, the Company adopted the RSP Permian, Inc. 2014 Long Term Incentive Plan (the "LTIP") for the employees, consultants and directors of the Company and its affiliates who perform services for the Company.

Equity-based compensation expense for awards under the LTIP was $2.5 million and $1.9 million for the three months ended September 30, 2017 and 2016, respectively. This equity-based compensation expense was $7.5 million and $6.0 million for the nine months ended September 30, 2017 and 2016, respectively.

The Company views restricted stock awards with graded vesting as single awards with an expected life equal to the average expected life and amortize the awards on a straight-line basis over the life of the awards.

The compensation expense for these awards was determined based on the market price of the Company's common stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of September 30, 2017, the Company had unrecognized compensation expense of $15.5 million related to restricted stock awards which is expected to be recognized over a weighted average period of 1.6 years.

The following table represents restricted stock award activity for the nine months ended September 30 2017 and the twelve months ended December 31, 2016:

	2017		2016	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	656,895	$ 22.21	499,529	$ 25.99
Restricted shares granted	355,579	41.85	442,835	19.78
Restricted shares canceled	(24,109)	31.76	(13,551)	21.61
Restricted shares vested	(278,849)	23.46	(271,918)	25.22
Restricted shares outstanding, end of period	709,516	$ 31.24	656,895	$ 22.21

Performance-Based Restricted Stock Awards

In June 2014, performance-based restricted stock awards were granted containing predetermined market conditions with a cliff vesting period of 2.75 years. We granted 134,400 of these shares at a 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target. In March 2015, an additional grant of performance-based restricted stock awards were granted containing predetermined market conditions with a cliff vesting period of 2.83 years. We granted 159,932 of these shares at a 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target. In February 2016, an additional grant of performance-based restricted stock awards were granted containing predetermined market conditions with a cliff vesting period of 2.92 years. We granted 484,650 of these shares at a 100% of target payout while the conditions of the grants allow for a payout ranging from no payout and 100% of target payout. In February 2017, an additional grant of performance-based restricted stock awards were granted

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containing predetermined market conditions with a cliff vesting period of 2.92 years. We granted 380,174 of these shares at a 100% of target payout while the conditions of the grants allow for a payout ranging from no payout and 100% of target payout.

Equity-based compensation for these awards was $1.8 million and $1.3 million for the three months ended September 30, 2017 and 2016, respectively. This equity-based compensation expense was $5.2 million and $4.5 million for the nine months ended September 30, 2017 and 2016, respectively.

The compensation expense for these performance based awards is based on a per share value using a Monte-Carlo simulation. The payout level is calculated based on actual total shareholder return performance achieved during the performance period compared to a defined peer group of comparable public companies. The unrecognized compensation expense related to these shares is approximately $11.2 million as of September 30, 2017 and is expected to be recognized over the next 1.5 years.

The following table represents performance-based restricted stock award activity for the nine months ended September 30 2017 and the twelve months ended December 31, 2016:

	2017		2016	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	747,874	$ 19.82	294,332	$ 31.41
Restricted shares granted	380,174	26.96	484,650	13.53
Restricted shares canceled	(7,569)	26.96	—	—
Restricted shares vested	(119,400)	31.01	(31,108)	31.39
Restricted shares outstanding, end of period	1,001,079	$ 21.14	747,874	$ 19.82

NOTE 9—EARNINGS PER SHARE

The Company’s basic earnings per share amounts have been computed using the two-class method based on the weighted-average number of shares of common stock outstanding for the period. Because the Company recognized a net loss for the nine months ended September 30, 2016, all unvested restricted share awards were excluded from diluted earnings per share calculations for this period as they would be antidilutive. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended September 30,	
	2017	2016
	(In thousands, except per share data)	
Numerator:		
Net income (loss) available to stockholders	$21,326	$ 985
Basic net income allocable to participating securities (1)	107	7
Income (loss) available to stockholders	$21,219	$ 978
Denominator:		
Weighted average number of common shares outstanding - basic	156,864	100,234

Effect of dilutive securities:		
Restricted stock	973	—
Weighted average number of common shares outstanding - diluted	157,837	100,234
Net income (loss) per share:		
Basic	$0.14	$ 0.01
Diluted	$0.14	$ 0.01

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(1) Restricted share awards that contain non-forfeitable rights to dividends are participating securities and, therefore, are included in computing earnings using the two-class method. Participating securities, however, do not participate in undistributed net losses.

	Nine Months Ended September 30,	
	2017	2016
	(In thousands, except per share data)	
Numerator:		
Net income (loss) available to stockholders	$91,350	$(26,234)
Basic net income allocable to participating securities (1)	457	—
Income (loss) available to stockholders	$90,893	$(26,234)
Denominator:		
Weighted average number of common shares outstanding - basic	153,258	100,161
Effect of dilutive securities:		
Restricted stock	1,020	—
Weighted average number of common shares outstanding - diluted	154,278	100,161
Net income (loss) per share:		
Basic	$0.59	$(0.26)
Diluted	$0.59	$(0.26)

(1) Restricted share awards that contain non-forfeitable rights to dividends are participating securities and, therefore, are included in computing earnings using the two-class method. Participating securities, however, do not participate in undistributed net losses.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes in "Part I, Item 1. Financial Statements." The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions and resources. Please see "Cautionary Statement Concerning Forward-Looking Statements" elsewhere in this Quarterly Report on Form 10-Q and "Part I, Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2016.

Overview and Outlook

Our financial and operating performance and significant events in the first nine months of 2017 include the following highlights:

- Increased our average daily production rate by 98% for the third quarter of 2017 as compared to the same period in 2016, and by 8% as compared to the second quarter of 2017.
- Participated in drilling 35 gross horizontal wells (26 operated) and completed 28 gross horizontal wells (22 operated) during the third quarter of 2017.
- Increased our borrowing base under the revolving credit facility to $1.5 billion in October 2017.
- In March 2017, closed on the previously-announced SHEP II acquisition for an aggregate purchase price of approximately $646 million of cash and 16.0 million shares of RSP Inc. common stock in aggregate. The cash portion of the purchase price was funded with cash on hand.
- Acquired approximately $265.1 million of additional oil and gas properties.
- Acquired water infrastructure assets which service Delaware Basin properties for an aggregate purchase price of $18.8 million.

Our average daily production rate during the third quarter of 2017 was 58,932 Boe/d, a 98% increase from our third quarter 2016 average daily production of 29,761 Boe/d, and an 8% increase from our second quarter 2017 average daily production of 54,341 Boe/d. Oil production was 71% of total production on a volumetric basis and 86% of our total revenues in the third quarter of 2017.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our operations, including:

- production volumes;
- revenues on the sale of oil, NGLs and natural gas, including the effect of our commodity derivative contracts on our production;
- operating expenses; and
- capital efficiency

Due to the inherent volatility in commodity prices, we have historically used commodity derivative instruments, such as collars, swaps and puts, to hedge price risk associated with a significant portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in commodity prices and provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in commodity prices and may partially limit our potential gains from future increases in prices. None of our instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge a portion of our physical production in order to protect our returns. Our revolving credit facility limits our ability to enter into commodity hedges covering greater than 85% of our reasonably projected production volume.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. We are not under an obligation to hedge a specific portion of our production. For information regarding the summary of open positions, see Note 4 of Notes to Consolidated Financial Statements included in “Part I, Item 1. Financial Statements.”

2017 Capital Budget

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Our board of directors approved a capital budget range for drilling, completion, and infrastructure for 2017 of approximately $625 to $700 million. We continuously monitor commodity prices, our cash flow and returns to determine adjustments to our capital budget. We intend to allocate our 2017 capital budget approximately as follows:

- $575 to $625 million for drilling and completion activities; approximately 10% of which is non-operated drilling and completion activities; and
- $50 to $75 million for infrastructure and other expenditures.

During the first nine months of 2017, we spent approximately $448.1 million on drilling and completion activities and $38.7 million on infrastructure and other expenditures.

Our 2017 capital budget excludes acquisitions and additions to leasehold and is subject to change depending upon a number of factors, including prevailing and anticipated prices for oil, NGLs and natural gas, results of horizontal drilling and completions, economic and industry conditions at the time of drilling, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Results of Operations

Three Months Ended September 30, 2017 Compared to the Three Months Ended September 30, 2016

Oil, NGLs and Natural Gas Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Three Months Ended September 30,			
	2017	2016	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$174,624	$84,722	$89,902	106 %
Natural gas sales	9,661	3,901	5,760	148 %
NGL sales	17,369	4,998	12,371	248 %
Total revenues	$201,654	$93,621	$108,033	115 %
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$45.85	$42.60	$3.25	8 %
Oil (per Bbl) (after impact of cash settled derivatives)	45.16	41.46	3.70	9 %
Natural gas (per Mcf) (excluding impact of cash settled derivatives)	2.23	2.27	(0.04)	(2)%
Natural gas (per Mcf) (after impact of cash settled derivatives)	2.24	2.27	(0.03)	(1)%
NGLs (per Bbl)	19.52	10.82	8.70	80 %
Total (per Boe) (excluding impact of cash settled derivatives)	$37.19	$34.19	$3.00	9 %
Total (per Boe) (after impact of cash settled derivatives)	$36.72	$33.37	$3.35	10 %
Production:				
Oil (MBbls)	3,808	1,989	1,819	91 %
Natural gas (MMcf)	4,339	1,720	2,619	152 %
NGLs (MBbls)	890	462	428	93 %
Total (MBoe)	5,422	2,738	2,684	98 %
Average daily production volume:				
Total (Boe/d)	58,932	29,761	29,171	98 %

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The following table shows the relationship between our average realized oil price as a percentage of the average NYMEX price and the relationship between our average realized natural gas price as a percentage of the average NYMEX price for the periods indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues. The NYMEX WTI futures price is a widely-used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the ability to transport crude oil to the transportation hubs or refineries. The NYMEX Henry Hub price of natural gas is a widely-used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, depending on pricing, liquids rich natural gas with a high Btu content may sell at a premium to low Btu content dry natural gas because it yields a greater quantity of NGLs. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds.

	Three Months Ended September 30,	
	2017	2016
Average realized oil price ($/Bbl)	$45.85	$42.60
Average NYMEX ($/Bbl)	48.20	44.94
Differential to NYMEX	(2.35)	(2.34)
Average realized oil price to NYMEX percentage	95%	95%
Average realized natural gas price ($/Mcf)	$2.23	$2.27
Average NYMEX ($/Mcf)	2.99	2.81
Differential to NYMEX	(0.76)	(0.54)
Average realized natural gas price to NYMEX percentage	75%	81%
Average realized NGL price ($/Bbl)	$19.52	$10.82
Average NYMEX oil price ($/Bbl)	48.20	44.94
Average realized NGL price to NYMEX oil price percentage	40%	24%

All of our oil contracts are impacted by the Midland-Cushing differential, which was a negative $0.75 and a negative $0.31 per Bbl for the third quarters of 2017 and 2016, respectively.

Oil revenues increased 106% to $174.6 million for the three months ended September 30, 2017 from $84.7 million for the applicable 2016 period as a result of an increase in oil production volumes of 1,819 MBbls, or 91%, and a $3.25 per Bbl increase, or 8%, in our average realized price for oil.

Natural gas revenues increased 148% to $9.7 million for the three months ended September 30, 2017 from $3.9 million for the applicable 2016 period as a result of an increase in natural gas production volumes of 2,620 MMcf, or 152%, partially offset by a decrease of $0.04 per Mcf, or 2%, in our average realized natural gas price.

NGL revenues increased 248% to $17.4 million for the three months ended September 30, 2017 from $5.0 million for the applicable 2016 period as a result of a $8.70 per Bbl increase, or 80%, in our average realized NGL price and an increase in NGL production volumes of 428 MBbls, or 93%.

Our higher production volumes for all products were primarily a result of increased production from our drilling program, along with the impact of our acquisitions that closed in 2016 and 2017.

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Operating Expenses. The following table summarizes our expenses for the periods indicated:

	Three Months Ended September 30,			
	2017	2016	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$33,385	$14,174	$19,211	136 %
Production and ad valorem taxes	13,281	5,872	7,409	126 %
Depreciation, depletion and amortization	73,408	50,022	23,386	47 %
Asset retirement obligation accretion	151	118	33	28 %
Impairment of unproved properties	705	971	(266)	(27)%
Exploration expenses	1,497	359	1,138	NM
General and administrative expenses	12,120	8,857	3,263	37 %
Acquisition costs	30	—	30	100 %
Total operating expenses	$134,577	$80,373	$54,204	67 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$5.18	$4.67	$0.51	11 %
Gathering and transportation	0.98	0.51	0.47	92 %
Production and ad valorem taxes	2.45	2.14	0.31	14 %
Depreciation, depletion and amortization	13.54	18.27	(4.73)	(26)%
Asset retirement obligation accretion	0.03	0.04	(0.01)	(25)%
Impairment	0.13	0.35	(0.22)	(63)%
Exploration expenses	0.28	0.13	0.15	NM
General and administrative - cash component	1.43	2.04	(0.61)	(30)%
General and administrative - stock comp (1)	0.81	1.20	(0.39)	(33)%
Acquisition costs	0.01	—	0.01	100 %
Total operating expenses per Boe	$24.84	$29.35	$(4.51)	(15)%

(1) Represents non-cash compensation expense related to restricted stock awards and performance share awards granted as part of the Company's ongoing compensation and retention program.

Lease Operating Expenses. Lease operating expenses increased to $33.4 million for the three months ended September 30, 2017 from $14.2 million for the applicable 2016 period due to a 98% increase in production. On a per-Boe basis, lease operating expense, excluding gathering and transportation costs, increased 11% from $4.67 per Boe in 2016 to $5.18 per Boe in 2017. Gathering and transportation costs, which are included in lease operating expenses, were $5.3 million for the three months ended September 30, 2017 and $1.4 million for the 2016 period. On a per-Boe basis, during the 2017 period our gathering and transportation costs increased 92% to $0.98 per Boe for the three months ended September 30, 2017 compared to the 2016 period. The increase in our gathering and transportation costs was primarily related to higher fee arrangements on midstream services used for our Delaware Basin properties.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 126% to $13.3 million for the three months ended September 30, 2017 from $5.9 million for the applicable 2016 period primarily due to higher production volumes and revenues, as well as increases in property taxes related to our Silver Hill properties. On a per-Boe basis, production and ad valorem taxes increased to $2.45 per Boe for the three months ended September 30, 2017 from $2.14 per Boe for the applicable 2016 period.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (“DD&A”) expense increased 47% to $73.4 million for the three months ended September 30, 2017 from $50.0 million for the applicable 2016 period due to increased production. The DD&A rate decreased 26% to $13.54 per Boe for the three months ended September 30, 2017 from $18.27 per Boe for the applicable 2016 period. The decrease in depletion per Boe in 2017 was due to an increase in our reserve volumes over the last year from acquisitions as well as successful drilling activities, partially offset by an increase in capitalized costs in proved property over the last year from these same activities.

Impairment of Unproved Properties. We incurred $0.7 million and $1.0 million of impairment expense on our unproved property for the three months ended September 30, 2017 and 2016, respectively. These impairments related to acreage lease

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expirations that we do not intend to extend or develop, along with certain leasehold interests that may expire or could be disposed of in the future. We may incur additional unproved property impairments in the future due to acreage expirations and changes in development plans. We may incur proved property impairments in the future if commodity prices experience sustained declines and remain low. The possibility and amount of any future impairment is difficult to predict, and will depend, in part, upon future oil and gas prices, estimates of proved reserves and future capital expenditures and production costs.

Exploration Expenses. Exploration expense increased to $1.5 million for the three months ended September 30, 2017 from $0.4 million for the applicable 2016 period due to an increase in expenditures on geological and geophysical activity in 2017. The activity in 2017 primarily relates to seismic projects on recently acquired acreage in the Delaware Basin.

General and Administrative Expenses. General and administrative expenses increased to $12.1 million for the three months ended September 30, 2017, from $8.9 million for the applicable 2016 period primarily due to increases in employee headcount and related expense including equity-based compensation. Equity-based compensation expense, which was recorded in general and administrative expenses, was $4.4 million for the three months ended September 30, 2017 and $3.3 million for the applicable 2016 period.

Other Income and Expenses. The following table summarizes our other income and expenses:

	Three Months Ended September 30,			
	2017	2016	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income, net	$1,106	$310	$796	257 %
Net gain (loss) on derivative instruments	(21,626)	(2,934)	(18,692)	(637)%
Interest expense	(21,553)	(13,146)	(8,407)	64 %
Total other income (expense)	$(42,073)	$(15,770)	$(26,303)	167 %

Net Gain (Loss) on Derivative Instruments. During the three months ended September 30, 2017, we recorded a $21.6 million net loss on derivative instruments as compared to a $2.9 million net loss in the applicable 2016 period. The change was a result of new contracts on derivative positions entered into over the last year and the higher future commodity price outlook as of September 30, 2017 as compared to September 30, 2016.

Interest Expense. During the three months ended September 30, 2017, we recorded $21.6 million of interest expense as compared to $13.1 million in the applicable 2016 period. Interest expense was higher than the prior-year period as a result of the issuance of additional senior notes in December 2016 and increased borrowings under our revolving credit facility compared to the applicable 2016 period.

Income Tax (Expense) Benefit. During the three months ended September 30, 2017, we recorded $3.7 million of income tax expense compared to $3.5 million of income tax benefit in the applicable 2016 period. The increase was largely related to a pretax book income during the three months ended September 30, 2017, compared to the three months ended September 30, 2016.

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Results of Operations

Nine Months Ended September 30, 2017 Compared to the Nine Months Ended September 30, 2016

Oil, NGLs and Natural Gas Sales Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Nine Months Ended September 30,				
	2017	2016	Change	% Change	
Revenues (in thousands, except percentages):					
Oil sales	$486,656	$211,212	$275,444	130	%
Natural gas sales	26,898	8,841	18,057	204	%
NGL sales	41,131	10,869	30,262	278	%
Total revenues	$554,685	$230,922	$323,763	140	%
Average sales prices:					
Oil (per Bbl) (excluding impact of cash settled derivatives)	$46.94	$38.74	$8.20	21	%
Oil (per Bbl) (after impact of cash settled derivatives)	46.33	38.86	7.47	19	%
Natural gas (per Mcf) (excluding impact of cash settled derivatives)	2.46	1.80	0.66	37	%
Natural gas (per Mcf) (after impact of cash settled derivatives)	2.49	1.80	0.69	38	%
NGLs (per Bbl)	18.32	9.80	8.52	87	%
Total (per Boe) (excluding impact of cash settled derivatives)	$38.43	$31.29	$7.14	23	%
Total (per Boe) (after impact of cash settled derivatives)	$38.01	$31.38	$6.63	21	%
Production:					
Oil (MBbls)	10,367	5,452	4,915	90	%
Natural gas (MMcf)	10,916	4,910	6,006	122	%
NGLs (MBbls)	2,245	1,109	1,136	102	%
Total (MBoe)	14,432	7,379	7,053	96	%
Average daily production volume:					
Total (Boe/d)	52,864	26,931	25,933	96	%

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The following table shows the relationship between our average realized oil price as a percentage of the average NYMEX price and the relationship between our average realized natural gas price as a percentage of the average NYMEX price for the periods indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues. The NYMEX WTI futures price is a widely-used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the ability to transport crude oil to the transportation hubs or refineries. The NYMEX Henry Hub price of natural gas is a widely-used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, depending on pricing, liquids rich natural gas with a high Btu content may sell at a premium to low Btu content dry natural gas because it yields a greater quantity of NGLs. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds.

	Nine Months Ended September 30,	
	2017	2016
Average realized oil price ($/Bbl)	$46.94	$38.74
Average NYMEX ($/Bbl)	49.47	41.33
Differential to NYMEX	(2.53)	(2.59)
Average realized oil price to NYMEX percentage	95%	94%
Average realized natural gas price ($/Mcf)	$2.46	$1.80
Average NYMEX ($/Mcf)	3.17	2.28
Differential to NYMEX	(0.71)	(0.48)
Average realized natural gas price to NYMEX percentage	78%	79%
Average realized NGL price ($/Bbl)	$18.32	$9.80
Average NYMEX oil price ($/Bbl)	49.47	41.33
Average realized NGL price to NYMEX oil price percentage	37%	24%

All of our oil contracts are impacted by the Midland-Cushing differential, which was a negative $0.31 per Bbl for the nine months ended September 30, 2017 and a negative $0.11 per Bbl for the applicable 2016 period.

Oil revenues increased 130% to $486.7 million for the nine months ended September 30, 2017 from $211.2 million for the applicable 2016 period as a result of an increase in oil production volumes of 4,915 MBbls, or 90% and a $8.20 per Bbl increase, or 21%, in our average realized price for oil.

Natural gas revenues increased 204% to $26.9 million for the nine months ended September 30, 2017 from $8.8 million for the applicable 2016 period as a result of a 122% increase in natural gas production volumes of 6,006 MMcf and a 37%, or $0.66 per Mcf increase in our average realized price for natural gas.

NGL revenues increased 278% to $41.1 million for the nine months ended September 30, 2017 from $10.9 million for the applicable 2016 period as a result of a $8.52 per Bbl increase, or 87%, in our average realized NGL price and an increase in NGL production volumes of 1,136 MBbls, or 102%.

Our higher production volumes for all products were primarily a result of increased production from our drilling program, along with the impact of our acquisitions that closed in 2016 and 2017.

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Operating Expenses. The following table summarizes our expenses for the periods indicated:

	Nine Months Ended September 30,			
	2017	2016	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$87,688	$41,359	$46,329	112 %
Production and ad valorem taxes	32,892	14,985	17,907	119 %
Depreciation, depletion and amortization	202,552	141,877	60,675	43 %
Asset retirement obligation accretion	454	354	100	28 %
Impairment of unproved properties	6,142	4,322	1,820	42 %
Exploration expenses	6,946	828	6,118	NM
General and administrative expenses	36,175	25,997	10,178	39 %
Acquisition costs	4,483	—	4,483	100 %
Total operating expenses	$377,332	$229,722	$147,610	64 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$5.09	$5.16	$(0.07)	(1)%
Gathering and transportation	0.99	0.44	0.55	125 %
Production and ad valorem taxes	2.28	2.03	0.25	12 %
Depreciation, depletion and amortization	14.03	19.23	(5.20)	(27)%
Asset retirement obligation accretion	0.03	0.05	(0.02)	(40)%
Impairment	0.43	0.59	(0.16)	(27)%
Exploration expenses	0.48	0.11	0.37	NM
General and administrative - cash component	1.62	2.09	(0.47)	(22)%
General and administrative - stock comp (1)	0.88	1.34	(0.46)	(34)%
General and administrative - non-recurring stock comp (2)	—	0.09	(0.09)	(100)%
Acquisition costs	0.31	—	0.31	100 %
Total operating expenses per Boe	$26.14	$31.13	$(4.99)	(16)%

(1) Represents non-cash compensation expense related to restricted stock awards and performance share awards granted as part of the Company's ongoing compensation and retention program.
(2) Represents a compensation charge associated with the retirement of an officer of the Company.

Lease Operating Expenses. Lease operating expenses increased to $87.7 million for the nine months ended September 30, 2017 from $41.4 million for the applicable 2016 period due to a 96% increase in production. On a per-Boe basis, lease operating expense, excluding gathering and transportation costs, decreased 1% from $5.16 per Boe in 2016 to $5.09 per Boe in 2017. Gathering and transportation costs, which are included in lease operating expenses, were $14.3 million for the nine months ended September 30, 2017 and $3.2 million for the 2016 period. On a per-Boe basis, our gathering and transportation costs increased 125% to $0.99 per Boe for the nine months ended September 30, 2017 compared to the 2016 period. The increase in our gathering and transportation costs was primarily related to higher fee arrangements on midstream services used for our Delaware Basin properties.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 119% to $32.9 million for the nine months ended September 30, 2017 from $15.0 million for 2016 primarily due to higher production volumes and revenues in the 2017 period, and increased 12% on a per-Boe basis to $2.28 per Boe for the nine months ended September 30, 2017 due to higher revenues per Boe.

Depreciation, Depletion and Amortization. DD&A expense increased 43% to $202.6 million for the nine months ended September 30, 2017 from $141.9 million for the 2016 period due to increased production. The DD&A rate decreased 27% to $14.03 per Boe for the nine months ended September 30, 2017 from $19.23 per Boe for the applicable 2016 period. The decrease in depletion per Boe in 2017 was due to an increase in our reserve volumes over the last year from acquisitions as well as successful drilling activities, partially offset by an increase in capitalized costs in proved property over the last year from these same activities.

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Impairment of Unproved Properties. We incurred $6.1 million and $4.3 million of impairment expense on our unproved property for the nine months ended September 30, 2017 and 2016, respectively. These impairments related to acreage lease expirations that we do not intend to extend or develop, along with certain leasehold interests that may expire or could be disposed of in the future. We may incur additional unproved property impairments in the future due to acreage expirations and changes in development plans. We may incur proved property impairments in the future if commodity prices experience sustained declines and remain low. The possibility and amount of any future impairment is difficult to predict, and will depend, in part, upon future oil and gas prices, estimates of proved reserves and future capital expenditures and production costs.

Exploration Expenses. Exploration expense increased to $6.9 million for the nine months ended September 30, 2017 from $0.8 million for the applicable 2016 period due to an increase in expenditures on geological and geophysical activity in 2017. The activity primarily relates to seismic projects on recently acquired acreage in the Delaware Basin.

General and Administrative Expenses. General and administrative expenses increased to $36.2 million for the nine months ended September 30, 2017, from $26.0 million for the applicable 2016 period primarily due to increases in employee headcount and related expense including equity-based compensation. Equity-based compensation expense, which was recorded in general and administrative expenses, was $12.7 million for the nine months ended September 30, 2017 and $10.5 million for the applicable 2016 period.

Other Income and Expenses. The following table summarizes our other income and expenses:

	Nine Months Ended September 30,			
	2017	2016	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income, net	$2,415	$587	$1,828	311 %
Net gain (loss) on derivative instruments	7,689	(6,222)	13,911	NM
Interest expense	(60,285)	(39,041)	(21,244)	54 %
Total other income (expense)	$(50,181)	$(44,676)	$(5,505)	12 %

Net Gain (Loss) on Derivative Instruments. During the nine months ended September 30, 2017, we recorded a $7.7 million net gain on derivative instruments as compared to a $6.2 million net loss in the applicable 2016 period. The change was a result of new contracts on derivative positions entered into over the last year and the future commodity price outlook as of September 30, 2017 as compared to September 30, 2016.

Interest Expense. During the nine months ended September 30, 2017, we recorded $60.3 million of interest expense as compared to $39.0 million in the applicable 2016 period. Interest expense was higher than the prior-year period as a result of the issuance of additional senior notes in December 2016 and increased borrowings under our revolving credit facility compared to the applicable 2016 period.

Income Tax (Expense) Benefit. During the nine months ended September 30, 2017, we recorded $35.8 million of income tax expense compared to $17.2 million of income tax benefit in the applicable 2016 period. The increase was largely related to a pretax book income during the nine months ended September 30, 2017, compared to a pretax book loss during the nine months ended September 30, 2016

Capital Requirements and Sources of Liquidity

Our primary sources of liquidity have been proceeds from equity offerings, borrowings under our revolving credit facility, proceeds from the issuance of senior notes, and cash flows from operations. To date, our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. At September 30, 2017, we had $345.0 million of borrowings outstanding under our revolving credit facility and our borrowing base was $1.1 billion with a Company-elected commitment of $900 million. In October 2017, we increased our borrowing base to $1.5 billion and maintained our elected commitment at $900 million.

During the third quarter of 2017, we spent approximately $168.9 million on drilling and completion activities, $22.7 million on infrastructure and other expenditures, and $234.4 million on oil and natural gas property acquisitions. In the first nine months of 2017, we spent approximately $448.1 million on drilling and completion activities, $38.7 million on infrastructure and other expenditures, and $913.7 million on oil and natural gas property acquisitions.

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We operate a high percentage of our acreage; therefore, the amount and timing of these capital expenditures are largely discretionary. We may elect to defer a portion of planned capital expenditures depending on a variety of factors, including: returns generated by our drilling program, the level of our expenditures in relation to our cash flow, the success of our drilling activities; prevailing and anticipated prices for oil, NGLs and natural gas; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; drilling, completion and acquisition costs; and the level of participation by other working interest owners.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our revolving credit facility to execute our current capital program excluding any acquisitions we may consummate. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, our ability to integrate our current acquisitions, and additional capital expenditures may be required to more fully develop our properties. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through borrowings under our revolving credit facility, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. We cannot provide assurance that needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

Working Capital

Our working capital, which we define as current assets minus current liabilities, was a negative $31.5 million and positive $668.0 million at September 30, 2017 and December 31, 2016, respectively. The significant working capital balance at December 31, 2016 related to cash raised in capital market transactions to fund the SHEP II transaction which closed in March 2017. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $46.5 million and $690.8 million at September 30, 2017 and December 31, 2016, respectively. Due to the amounts that accrue related to our drilling program, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our revolving credit facility will be sufficient to fund our working capital needs excluding any acquisitions we may consummate. We expect that our pace of development, production volumes, commodity prices, acquisition integrations and differentials to NYMEX prices for our oil, NGL and natural gas production will be the largest variables affecting our working capital.

Contractual Obligations

For the nine months ended September 30, 2017, we had no material changes in our contractual commitments and obligations from amounts listed under "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Requirements and Sources of Liquidity - Contractual Obligations" in our Annual Report on Form 10-K for the year ended December 31, 2016 other than $345.0 million in borrowings under our revolving credit facility expiring in 2021, compared to no outstanding borrowings at December 31, 2016.

Off-Balance Sheet Arrangements

As of September 30, 2017, we did not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources and would be considered material to investors.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

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	Nine Months Ended September 30,	
	2017	2016
	(In thousands)	
Net cash provided by operating activities	$344,882	$119,765
Net cash used in investing activities	(1,325,580)	(272,417)
Net cash provided by financing activities	336,396	32,287

Net cash provided by operating activities was approximately $344.9 million and $119.8 million for the nine months ended September 30, 2017 and 2016, respectively. The increase in net cash provided by operating activities for the nine months ended September 30, 2017, as compared to the 2016 period, was primarily a result of increased production from our drilling program, increased realized pricing for all our products along with the impact of our SHEP I and SHEP II acquisitions that closed in 2016 and 2017, respectively.

Net cash used in investing activities was approximately $1,325.6 million and $272.4 million for the nine months ended September 30, 2017 and 2016, respectively. The increase in cash used in investing activities was primarily due to the cash portion of the purchase price associated with the SHEP II acquisition in the 2017 period and increased drilling and completion activity in 2017.

Net cash provided by financing activities was $336.4 million and $32.3 million for the nine months ended September 30, 2017 and 2016, respectively. The increase in cash provided is primarily due to borrowings under our revolving credit facility to fund a portion of our drilling activity and acquisitions in the 2017 period.

Our Revolving Credit Facility

As of September 30, 2017, our credit agreement had a borrowing base of $1.1 billion, an elected commitment amount of $900 million, lenders' maximum facility commitments of $2.5 billion, and a maturity date of December 19, 2021. The credit agreement permits RSP LLC to make payments to the Company to enable it to pay principal, premium (if any) and interest on our existing senior notes, provided no default has occurred, and to allow RSP LLC to guarantee the existing senior notes.

The amount available to be borrowed under our revolving credit facility is subject to a borrowing base that is redetermined semiannually each May and November and depends on the volumes of our proved oil and natural gas reserves, estimated cash flows from these reserves and our commodity hedge positions. As of September 30, 2017, we had $345.0 million of borrowings and $0.4 million of letters of credit outstanding under our revolving credit facility and $554.6 million of borrowing capacity. In the event of any future offerings of senior unsecured notes issued or guaranteed by RSP LLC, the borrowing base under our revolving credit facility will be automatically reduced by an amount equal to 0.25 multiplied by the aggregate principal amount of notes issued or guaranteed on the date of such issuance. In October 2017, we increased our borrowing base to $1.5 billion and maintained our elected commitment at $900 million.
Our revolving credit facility is secured by liens on substantially all of our properties and guarantees from our subsidiaries other than any subsidiary that we have designated as an unrestricted subsidiary.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- make loans to others;
- make investments;
- enter into mergers;

- make or declare dividends;
- enter into commodity hedges exceeding a specified percentage or our expected production;
- enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

Our revolving credit facility also requires us to maintain the following two financial ratios:

- a working capital ratio, which is the ratio of consolidated current assets (includes unused commitments under our revolving credit facility and excludes restricted cash and derivative assets) to consolidated current liabilities

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(excluding the current portion of long term debt under the credit facility and derivative liabilities), of not less than 1.0 to 1.0; and

- a leverage ratio, which is the ratio of the sum of all of the Company's debt to the consolidated EBITDAX (as defined in our revolving credit facility) for the four fiscal quarters then ended, of not greater than 4.25 to 1.0.

We were in compliance with such covenants and ratios as of September 30, 2017.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. The Company has a choice of borrowing at a Eurodollar rate or at the adjusted base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the quotient of: (i) the LIBOR Rate; divided by (ii) a percentage equal to 100% minus the maximum rate on such date at which the Administrative Agent is required to maintain reserves on "Eurocurrency Liabilities" as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of its borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's referenced rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized, plus a commitment fee ranging from 37.5 basis points to 50 basis points charged on the undrawn commitment amount. On October 19, 2017, the Company entered into a first amendment to our credit agreement which decreased the applicable margins for interest rates applicable to amounts outstanding under the revolving credit facility from a range of 200 to 300 basis points above the applicable reference rate for Eurodollar loans and 100 to 200 basis points above the applicable reference rate for alternate base rate loans to ranges of 150 to 250 basis points for Eurodollar loans and 50 to 150 basis points for alternate base rate loans. At September 30, 2017, the prime borrowing rate of interest under the Company's revolving credit facility was 4.25%. In November 2017, the Company exchanged $450.0 million of the 5.25% senior unsecured notes for registered notes with the same terms. The Company was in compliance with the provisions of the indenture governing the senior unsecured notes as of September 30, 2017.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our revenues are subject to market risk and are dependent on the pricing we receive for our oil, NGLs and natural gas production. Pricing for oil, NGLs and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. Our realized prices are primarily driven by the prevailing prices for oil and the prevailing spot prices for NGLs and natural gas. We use derivative contracts to reduce our exposure to the changes in the prices of these commodities. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with projected production levels. We do not use these instruments to engage in trading activities, and we do not speculate on commodity prices.

The fair value of our derivative contracts as of September 30, 2017 was a net liability of $3.8 million. For information regarding the terms of these hedges and open positions, see Note 4 of Notes to Consolidated Financial Statements included in “Part I, Item 1. Financial Statements.”

Counterparty and Customer Credit Risk

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. The counterparties to our derivative contracts currently in place have investment grade ratings.

Our principal exposures to credit risk are through receivables arising from joint operations and receivables from the sale of our oil and natural gas production due to the concentration of our oil and natural gas receivables with several significant

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customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit quality of our customers is high.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

At September 30, 2017, we had $345.0 million in borrowings outstanding that are subject to interest rate risk. We currently do not engage in any interest rate hedging activity.

Item 4. Controls And Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2017. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2017 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

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

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

From time to time, we are party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment related disputes. While the outcome of these proceedings cannot be predicted with certainty, we do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations or liquidity.

Item 1A. Risk Factors.

In addition to the other information set forth in this Quarterly Report on Form 10-Q, you should carefully consider the factors discussed in "Part I, Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2016, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or results of operations.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's repurchase of our common stock during the three months ended September 30, 2017:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased under the Plans or Programs
July 1, 2017 - July 31, 2017	775	$ 33.28	—	$ —
August 1, 2017 - August 31, 2017	645	$ 32.78	—	$ —
September 1, 2017 - September 30, 2017	374	$ 33.53	—	$ —
Total	1,794	$ 33.15	—	$ —

(1) These shares were withheld from employees to satisfy statutory tax withholding obligations arising upon the vesting of restricted shares under the LTIP.

Item 6. Exhibits.

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on January 29, 2014).
3.2	Amended and Restated Bylaws of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 21, 2016).

4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1/A (File No. 333-192268) filed with the SEC on January 13, 2014).
4.2	Registration Rights Agreement, dated as of January 23, 2014, among RSP Permian, Inc., RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, ACTOIL, LLC, Rising Star Energy Development Co., L.L.C. and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on January 29, 2014).
4.3	Stockholders' Agreement, dated as of January 23, 2014, among RSP Permian, Inc., RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, Rising Star Energy Development Co., L.L.C. and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on January 29, 2014).

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4.4	Indenture, dated as of September 26, 2014, by and among the Company, RSP Permian, L.L.C. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 2, 2014).
4.5	Form of Senior Note due 2022 (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 2, 2014).
4.6	Registration Rights Agreement, dated as of August 10, 2015, by and among the Company, RSP Permian, L.L.C. and Goldman, Sachs, & Co. (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on August 12, 2015).
4.7	Stockholder's Agreement, dated as of November 28, 2016, by and between the Company and Kayne Anderson Capital Advisors, LP (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 13, 2016).
4.8	Registration Rights Agreement, dated as of November 28, 2016, by and between the Company and Silver Hill Energy Partners Holdings, LLC (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 13, 2016).
4.9	Indenture, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 27, 2016).
4.10	Form of Senior Note due 2025 (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 27, 2016).
4.11	Registration Rights Agreement, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC, and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on December 27, 2016).
4.12	Registration Rights Agreement, dated as of March 1, 2017, by and between the Company and Silver Hill Energy Partners II, LLC (incorporated by reference to Exhibit 4.3 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 13, 2016).
4.13	First Amendment to Credit Agreement dated as of October 19, 2017, by and among RSP Permian, Inc., RSP Permian, L.L.C., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the SEC on October 23, 2017).
31.1(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Executive Officer.
31.2(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Financial Officer.
32.1(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Extension Schema Document.
101.CAL(a)	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF(a)	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB(a)	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE(a)	XBRL Taxonomy Extension Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this report and not "filed" as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

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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.

RSP PERMIAN, INC.

By: /s/ Scott McNeill
Scott McNeill
Chief Financial Officer and Director
(Principal Financial Officer)
Date: November 6, 2017

By: /s/ Uma L. Datla
Uma L. Datla
Chief Accounting Officer
(Principal Accounting Officer)
Date: November 6, 2017