RSP Permian, Inc.
Form 10-Q
August 08, 2016
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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 June 30, 2016

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	75219
(Address of principal executive offices)	(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. See definition of “large accelerated filer,” “accelerated filer” and “smaller reporting 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

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 101,642,584 shares of common stock outstanding at August 5, 2016.

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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 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.

“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.

“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.

“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.

"MMcf." One million cubic feet.

“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.

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"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 completion for production of an existing wellbore in another formation from which the well has been previously completed.

"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.

"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.

"WTI." West Texas Intermediate.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements in this Report, including, without limitation, statements containing the words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “will,” “may,” “should,” “would,” “could” or other similar expressions, and statemen 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. 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 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 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 the Company’s operating activities, access to and availability of transportation, processing and refining facilities, the financial strength of counterparties to the Company’s credit facility and derivative contracts and the purchasers of the Company’s production and service providers to the Company, 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, 2015.

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)

	June 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$32,855	$142,741
Accounts receivable	34,593	36,323
Derivative instruments	5,378	8,452
Other assets	35	24
Total current assets	72,861	187,540
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	3,249,109	3,076,051
Accumulated depletion	(451,586)	(357,524)
Total oil and natural gas properties, net	2,797,523	2,718,527
Other property and equipment, net	38,328	40,103
Total property, plant and equipment	2,835,851	2,758,630
OTHER LONG-TERM ASSETS		
Restricted cash	152	152
Other long-term assets	15,492	21,111
Total other long-term assets	15,644	21,263
TOTAL ASSETS	$2,924,356	$2,967,433
LIABILITIES AND STOCKHOLDERS’ EQUITY		
CURRENT LIABILITIES		
Accounts payable	$11,487	$15,569
Accounts payable, related party	—	6,459
Accrued expenses	37,277	39,231
Interest payable	12,022	12,149
Derivative instruments	7,131	3,994
Total current liabilities	67,917	77,402
LONG-TERM LIABILITIES		
Asset retirement obligations	8,962	7,063
Long-term debt	687,305	686,512
Deferred taxes	324,137	337,872
Total long-term liabilities	1,020,404	1,031,447
Total liabilities	1,088,321	1,108,849
STOCKHOLDERS' EQUITY		
Common stock, $.01 par value; 300,000,000 shares authorized, 101,644,885 shares issued and outstanding at June 30, 2016; 100,807,286 shares issued and outstanding at December 31, 2015	1,016	1,008
Additional paid-in capital	1,877,993	1,873,332
Accumulated deficit	(42,974)	(15,756)
Total stockholders' equity	1,836,035	1,858,584

TOTAL LIABILITIES AND STOCKHOLDERS’ EQUITY	$2,924,356	$2,967,433

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
REVENUES				
Oil sales	$74,799	$73,917	$126,490	$121,222
Natural gas sales	2,537	2,028	4,940	4,261
NGL sales	4,149	2,520	5,871	4,356
Total revenues	81,485	78,465	137,301	129,839
OPERATING EXPENSES				
Lease operating expenses	$14,094	$14,693	$27,185	$27,304
Production and ad valorem taxes	4,960	5,402	9,113	9,599
Depreciation, depletion and amortization	47,296	39,620	91,855	71,121
Asset retirement obligation accretion	123	84	236	168
Impairment of unproved properties	3,177	—	3,350	—
Exploration expenses	405	889	469	2,067
General and administrative expenses	9,135	6,865	17,140	13,236
Total operating expenses	79,190	67,553	149,348	123,495
OPERATING INCOME (LOSS)	2,295	10,912	(12,047)	6,344
OTHER INCOME (EXPENSE)				
Other income, net	$104	$(37)	$277	$161
Net loss on derivative instruments	(3,684)	(12,962)	(3,288)	(631)
Interest expense	(12,954)	(9,367)	(25,895)	(18,683)
Total other income (expense)	(16,534)	(22,366)	(28,906)	(19,153)
LOSS BEFORE TAXES	(14,239)	(11,454)	(40,953)	(12,809)
INCOME TAX BENEFIT	4,438	6,001	13,735	6,331
NET LOSS	$(9,801)	$(5,453)	$(27,218)	$(6,478)
Loss per common share:				
Basic	$(0.10)	(0.07)	$(0.27)	$(0.08)
Diluted	$(0.10)	(0.07)	$(0.27)	$(0.08)
Weighted average shares outstanding:				
Basic	100,189	83,088	100,125	80,639
Diluted	100,189	83,088	100,125	80,639

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 Deficit	Total Stockholders’ Equity
BALANCE AT DECEMBER 31, 2015	100,807	$ 1,008	$ 1,873,332	$ (15,756)	$ 1,858,584
Repurchase and retirement of common stock	(95)	(1)	(2,607)	—	(2,608)
Equity-based compensation	933	9	7,268	—	7,277
Net loss	—	—	—	(27,218)	(27,218)
BALANCE AT JUNE 30, 2016	101,645	$ 1,016	$ 1,877,993	$ (42,974)	$ 1,836,035

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)

	Six Months Ended June 30,	
	2016	2015
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$(27,218)	$(6,478)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	91,855	71,121
Asset retirement obligation accretion	236	168
Impairment of unproved properties	3,350	—
Equity-based compensation	7,277	4,543
Amortization of loan fees	1,301	978
Deferred income taxes	(13,735)	(3,954)
Other	115	74
Net loss on derivative instruments	3,288	631
Net cash receipts from settled derivatives	11,240	48,286
Changes in operating assets and liabilities:		
Accounts receivable	(6,596)	(26,256)
Other assets	5,920	(60)
Accounts payable and accounts payable to related parties	(10,541)	(12,782)
Accrued expenses	(916)	15,923
Interest payable	(127)	(575)
Net cash provided by operating activities	$65,449	$91,619
CASH FLOWS FROM INVESTING ACTIVITIES		
Development of oil and natural gas properties	(127,066)	(226,457)
Acquisitions of oil and natural gas properties	(43,489)	(15,618)
Additions to other property and equipment	(1,372)	(5,369)
Investment in unconsolidated subsidiary	(800)	(1,675)
Net cash used in investing activities	$(172,727)	$(249,119)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common stock	—	147,048
Borrowings under long-term debt	—	15,000
Payments on long-term debt	—	(15,000)
Repurchase and retirement of common stock	(2,608)	(1,785)
Net cash (used in) provided by financing activities	$(2,608)	$145,263
NET CHANGE IN CASH	$(109,886)	$(12,237)
CASH AT BEGINNING OF PERIOD	$142,741	$56,292
CASH AT END OF PERIOD	$32,855	$44,055
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash paid for interest	$24,704	$18,279
Cash paid for taxes	$2,000	$2,700
NON-CASH ACTIVITIES		
Asset retirement obligation acquired	$232	—
Change in accrued capital expenditures	$(1,038)	$13,661

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

NOTE 1—NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Organization and Description of the Business

RSP Permian, Inc. ("RSP Inc." or the "Company") was formed on September 30, 2013, pursuant to the laws of the state of Delaware to be a holding company for RSP Permian, L.L.C., a Delaware limited liability company ("RSP LLC"). RSP LLC was formed on October 18, 2010, by its management team and affiliates of Natural Gas Partners, a family of energy-focused private equity investment funds ("NGP"). The Company is 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 Company priced its initial public offering ("IPO") and began trading on the New York Stock Exchange under the ticker RSPP in January 2014. Additional background on the Company, its IPO and subsequent public stock offerings, along with details of the ownership of the Company, are available in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 and other documents filed with the Securities and Exchange Commission ("SEC").

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 statement 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, 2015, 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 June 30, 2016 in preparing its consolidated financial statements. There were no material subsequent events requiring additional disclosure in these consolidated financial statements.

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 are determined using estimates of proved oil and natural gas reserves. There are numerous 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.

Accounts Receivable

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	As of June 30, 2016	As of December 31, 2015
	(In thousands)	
Sale of oil, natural gas and natural gas liquids	$32,005	$ 22,166
Joint interest owners	2,342	5,596
Derivatives - settled, but uncollected	246	8,561
Total accounts receivable	$34,593	$ 36,323

Accounts receivable, which are primarily from the sale of oil, natural gas and natural gas liquids (“NGLs”), are accrued based on estimates of the volumetric sales and prices the Company believes it will receive. In addition, settled but uncollected derivative contracts, and receivables related to joint interest billings 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. Management's expectations are that all material receivables at period-end will be collected. Bad debt expense was zero for each of the six months ended June 30, 2016 and 2015, 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. Gains and losses arising from the sale of properties are generally included in operating income.

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 June 30, 2016 and 2015, depletion expense for oil and natural gas producing property was $46.9 million and $39.3 million, respectively. For the six months ended June 30, 2016 and 2015, depletion expense for oil and natural gas producing property was $91.1 million and $70.3 million, respectively. Depletion expense is included in depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The Company’s oil and natural gas properties as of June 30, 2016 and December 31, 2015 consisted of the following:

	June 30, 2016	December 31, 2015
	(In thousands)	
Proved oil and natural gas properties	$2,365,562	$2,197,056
Unproved oil and natural gas properties	883,547	878,995
Total oil and natural gas properties	3,249,109	3,076,051
Less: Accumulated depletion	(451,586)	(357,524)
Total oil and natural gas properties, net	$2,797,523	$2,718,527

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 June 30, 2016 and December 31, 2015, 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 and natural gas prices to the estimated future

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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.

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 six months ended June 30, 2016 or 2015. 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. It is reasonably possible that oil and natural gas prices used in future impairment evaluations may decline, which would result in the need to further impair the carrying value of the Company's 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 six months ended June 30, 2016, impairment expense of unproved property was $3.4 million, 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 be sold in the future. No impairment of unproved property was recorded for the six months ended June 30, 2015.

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 rate. If the estimated ARO changes, an adjustment is recorded to both the ARO 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 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 consisted of the following for the period indicated:

Six Months Ended

	June 30, 2016
	(In thousands)
Asset retirement obligation at beginning of period	$ 7,063
Liabilities incurred or assumed	1,691
Liabilities settled	(28)
Accretion expense	236
Asset retirement obligation at end of period	$ 8,962

Income Taxes

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The following is an analysis of the Company’s consolidated income tax benefit for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)		(In thousands)	
Current	$ —	$ (3,561)	$ —	$ (2,377)
Deferred	(4,438)	(2,440)	(13,735)	(3,954)
Income Tax Benefit	$ (4,438)	$ (6,001)	$ (13,735)	$ (6,331)

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 June 30, 2016, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

The Company’s U.S. federal income tax returns for 2011 and beyond, and its Texas franchise tax returns for 2010 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 March 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update ("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. Public entities are required to apply ASU 2016-09 for annual and interim reporting periods beginning after December 15, 2016. The Company is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842)," which requires all lease transactions (with 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 September 2015, the FASB issued ASU 2015-16, “Simplifying the Accounting for Measurement-Period Adjustments," which requires the acquirer in a business combination recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Public entities are required to apply ASU 2015-16 for annual and interim reporting periods beginning after December 15, 2015. The adoption of this guidance in the first quarter of 2016 did not have a material effect on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, “Simplifying the Presentation of Debt Issuance Costs." which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying amount of the debt obligation, similar to debt discounts. The Company adopted this guidance in the first quarter of 2016. Accordingly, debt issuance costs in the amount of $12.1 million which were formerly classified as long-term assets at December 31, 2015 have been reclassified as a deduction from the carrying amount of our senior notes in the consolidated balance sheet.

In January 2015, the FASB issued ASU 2015-01, "Income Statement - Extraordinary and Unusual Items (Subtopic 225-20)," which eliminates the concept of extraordinary items in US GAAP. An entity is required to apply ASU 2015-01 for annual and interim reporting periods beginning after December 15, 2015. An entity may apply ASU 2015-01 prospectively or retrospectively for all periods presented in the financial statements. The adoption of this guidance in the first quarter of 2016 did not have a material effect on the Company's consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, “Disclosure of Uncertainties About an Entity’s Ability to Continue as a Going Concern,” which requires a company’s management to evaluate whether there are conditions and events that raise substantial doubt about the entity's ability to continue as a going concern within one year after the financial statements are issued (or available to be issued when applicable). An entity is required to apply ASU 2014-15 for annual and interim reporting periods beginning after December 15, 2016 with early adoption permitted. The Company is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements.

In May 2014, the FASB issued 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, 2016. 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 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 is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements.

NOTE 3—ACQUISITIONS OF OIL AND NATURAL GAS PROPERTY INTERESTS

Recent Acquisitions

In the first six months of 2016, the Company closed on acquisitions of mostly undeveloped acreage for an aggregate total of approximately $43.5 million. The acquisitions included additional working interests in properties where we owned existing interests as well as other properties in our core areas, some of which we took over operations. These acquisitions were funded with cash on hand.

WPR Acquisition

In the fourth quarter of 2015, the Company acquired undeveloped acreage and oil and gas producing properties for an aggregate purchase price of approximately $137 million, subject to certain purchase price adjustments, from Wolfberry Partners Resources LLC ("WPR"), an entity partly owned by affiliates of the Company. Approximately $41.0 million was recorded as proved oil and gas properties. The acquisition included 4,100 largely contiguous net acres, in the core of the Midland Basin with production of approximately 1,900 Boe/d and 86 net horizontal drilling locations as of the effective date.

Glass Ranch Acquisition

In the third quarter of 2015, the Company acquired undeveloped acreage and oil and gas producing properties located in Martin and Glasscock counties for an aggregate purchase price of approximately $313 million, subject to certain purchase price adjustments. The aggregate acquisitions include 6,548 net acres in our core focus area with an average royalty burden of approximately 23%, with production of approximately 1,680 Boe/d and 191 net horizontal drilling locations as of the effective date.

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 include collar contracts and deferred premium put options. 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.

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

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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.

The following table summarizes all open positions as of June 30, 2016:

	Contracts expiring quarter ending: September 30, 2016	December 31, 2016	Total
Crude Oil Collars:			
Notional volume (Bbl)	120,000	120,000	240,000
Weighted average ceiling price ($/Bbl)(1)	$74.41	$ 74.41	$ 74.41
Weighted average floor price ($/Bbl)(1)	$55.00	$ 55.00	$ 55.00
Weighted average short put price ($/Bbl)(1)	$45.00	$ 45.00	$ 45.00
Deferred Premium Puts:			
Notional volume (Bbl)	1,410,000	1,125,000	2,535,000
Weighted average floor price ($/Bbl)(1)	$45.00	$ 45.00	$ 45.00
Weighted average deferred premium ($/Bbl)	$(2.59)	$ (2.74)	$ (2.65)

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(1) The crude oil derivative contracts are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude.

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. 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	
	June 30, 2016	December 31, 2015	June 30, 2016	December 31, 2015
	(In thousands)			
Derivative Instruments:				
Current amounts				
Commodity contracts	$5,378	$ 8,452	$(7,131)	$ (3,994)
Total derivative instruments	$5,378	$ 8,452	$(7,131)	$ (3,994)

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

The following represents the Company's reported gains on derivative instruments for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015

	(In thousands)		(In thousands)	
Loss on derivative instruments:				
Commodity derivative instruments	$(3,684)	$(12,962)	$(3,288)	$(631)
Total	$(3,684)	$(12,962)	$(3,288)	$(631)

Offsetting of Derivative Assets and Liabilities

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

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	Gross Amount Presented on Balance Sheet	Netting Adjustments(a)	Net Amount
	(In thousands)		
June 30, 2016			
Derivative instrument assets with right of offset or master netting agreements	$5,378	$ (5,378)	$—
Derivative instrument liabilities with right of offset or master netting agreements	$(7,131)	$ 5,378	$(1,753)
December 31, 2015			
Derivative instrument assets with right of offset or master netting agreements	$8,452	$ (3,994)	$4,458
Derivative instrument liabilities with right of offset or master netting agreements	$(3,994)	$ 3,994	$—

(a) With all of the Company's financial trading counterparties, the Company has agreements in place 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 June 30, 2016 and December 31, 2015.

NOTE 5—FAIR VALUE MEASUREMENTS

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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 credit facilities approximate fair value as the interest rates are variable. The book value of the Company's senior notes approximates the fair value as the current trading value of the notes was slightly above par value. If the Company recorded the 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. 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. These inputs 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 June 30, 2016:				
Commodity derivative instruments	$ —	$ (1,753)	$ —	$ (1,753)
Total	$ —	$ (1,753)	$ —	$ (1,753)

	Level 1	Level 2	Level 3	Total fair value
	(In thousands)			

As of December 31, 2015:						
Commodity derivative instruments	$	—	$ 4,458	$	—	$ 4,458
Total	$	—	$ 4,458	$	—	$ 4,458

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.

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Reclassifications of fair value between 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 between Level 1, Level 2 or Level 3 during the six months ended June 30, 2015 and the year ended December 31, 2015.

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:

	June 30, 2016	December 31, 2015
	(In millions)	
6.625% Senior Notes	$700.0	$ 700.0
Less: Discount	$(1.3)	$ (1.4)
Less: Debt issuance costs	$(11.4)	$ (12.1)
Total long-term debt	$687.3	$ 686.5

Credit Agreement

On August 24, 2015, the Company amended the revolving credit facility to increase the borrowing base to $600 million along with other updates.

The Company's revolving credit facility requires it to maintain the following three 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 4.5 to 1.0; and

•a senior secured leverage ratio, which is the ratio of the sum of all the Company's debt that is (i) secured and (ii) not subordinated to obligations under the revolving credit facility to the consolidated EBITDAX (as defined in the credit agreement) for the four fiscal quarters then ended, of not greater than 3.5 to 1.0.

The Company's revolving credit facility 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.

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The Company was in compliance with such covenants and ratios as of June 30, 2016.

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 in Eurodollars or at the alternate 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 100 to 200 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 100 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 0 to 100 basis points, depending on the percentage of its borrowing base utilized, plus a facility fee of 0.50% charged on the borrowing base amount. At June 30, 2016, the prime borrowing rate of interest under the Company’s revolving credit facility was 3.50%. RSP LLC may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. As of June 30, 2016, the revolving credit facility has a margin of 1.00% to 2.00% plus LIBOR, plus a facility fee of 0.50% charged on the borrowing base amount. As of June 30, 2016, we had no borrowings and $0.6 million of letters of credit outstanding under our revolving credit facility and $599.4 million of borrowing capacity.

The amount available to be borrowed under the revolving credit facility is subject to a borrowing base that is re-determined 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. The borrowing base under the Company’s amended and restated credit agreement is $600 million as of June 30, 2016, with lender commitments of $1 billion. The maturity date of the Company's revolving credit facility is August 29, 2019.

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 RSP LLC's 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. On or 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. In addition, prior to October 1, 2017, the Company may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 106.625% of the principal amount of the notes, plus accrued and unpaid interest.

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 holder of notes 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. RSP LLC, our 100% owned and only subsidiary, has fully and unconditionally guaranteed the notes. 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 June 30, 2016.

NOTE 7—COMMITMENTS AND CONTINGENCIES

Legal Matters

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

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

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both June 30, 2016 and December 31, 2015, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Contractual Obligations

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, 2015.

NOTE 8—EQUITY-BASED COMPENSATION

Equity-based compensation expense, which was recorded in general and administrative expenses, was $4.2 million and $2.4 million for the three months ended June 30, 2016 and 2015, respectively. This equity-based compensation expense was $7.3 million and $4.5 million for the six months ended June 30, 2016 and 2015, respectively.

Restricted Stock Awards

In connection with the IPO, 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 $2.2 million and $1.6 million for the three months ended June 30, 2016 and 2015, respectively. This same expense was $4.1 million and $3.2 million for the six months ended June 30, 2016 and 2015, respectively. In the second quarter of 2016, the vesting for certain shares was accelerated and resulted in $0.3 million of additional equity-based compensation expense.

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 June 30, 2016, the Company had unrecognized compensation expense of $12.2 million related to restricted stock awards which is expected to be recognized over a weighted average period of 2.1 years.

The following table represents restricted stock award activity for the six months ended June 30:

	2016		2015	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	499,529	$ 25.99	477,767	$ 23.71
Restricted shares granted	440,773	19.69	277,510	27.19
Restricted shares canceled	(13,551)	21.61	(4,289)	26.07
Restricted shares vested	(258,738)	25.20	(243,274)	22.84
Restricted shares outstanding, end of period	668,013	$ 22.23	507,714	$ 26.01

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.

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Equity-based compensation for these awards was $2.0 million and $0.8 million for the three months ended June 30, 2016 and 2015, respectively. This equity-based compensation expense was $3.2 million and $1.3 million for the six months ended June 30, 2016 and 2015, respectively. In the second quarter of 2016, the vesting for certain shares was accelerated and resulted in $0.4 million of additional equity-based compensation expense.

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 $9.2 million as of June 30, 2016 and is expected to be recognized over the next 1.97 years.

The following table represents performance-based restricted stock award activity for the six months ended June 30:

	2016		2015	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	294,332	$ 31.41	134,400	$ 28.14
Restricted shares granted	484,650	13.53	159,932	31.74
Restricted shares vested	(31,108)	$ 31.39	—	$ —
Restricted shares outstanding, end of period	747,874	$ 19.82	294,332	$ 31.41

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 each period presented below, all unvested restricted share awards were not recognized in diluted earnings per share calculations 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 June 30,	
	2016	2015
	(In thousands)	
Numerator:		
Net loss available to stockholders	$ (9,801)	$ (5,453)
Basic net loss allocable to participating securities (1)	—	—
Loss available to stockholders	$ (9,801)	$ (5,453)
Denominator:		
Weighted average number of common shares outstanding - basic	100,189	83,088
Effect of dilutive securities:		
Restricted stock	—	—
Weighted average number of common shares outstanding - diluted	100,189	83,088
Net loss per share:		
Basic	$ (0.10)	$ (0.07)
Diluted	$ (0.10)	$ (0.07)

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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.

	Six Months Ended June 30,	
	2016	2015
	(In thousands)	
Numerator:		
Net loss available to stockholders	$(27,218)	$(6,478)
Basic net loss allocable to participating securities (1)	—	—
Loss available to stockholders	$(27,218)	$(6,478)
Denominator:		
Weighted average number of common shares outstanding - basic	100,125	80,639
Effect of dilutive securities:		
Restricted stock	—	—
Weighted average number of common shares outstanding - diluted	100,125	80,639
Net loss per share:		
Basic	$(0.27)	$(0.08)
Diluted	$(0.27)	$(0.08)

(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.

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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, 2015.

Our Predecessor and RSP Inc.

RSP Inc. was formed in September 2013 and, prior to the consummation of our IPO, did not have historical financial operating results. The historical results of RSP LLC and Rising Star Energy Development Co., L.L.C. , our predecessor, have been consolidated for all periods presented prior to the IPO date. In connection with the IPO, pursuant to the terms of a corporate reorganization, RSP LLC became a wholly owned subsidiary of RSP Inc. RSP LLC was formed in 2010 to engage in acquisition, exploration, development, and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. See “Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: The IPO and Related Transactions - Corporate Reorganization” in our Annual Report on Form 10-K for the year ended December 31, 2015 for more information. Also in connection with the IPO, Rising Star contributed to RSP Inc. certain assets that represent substantially all of Rising Star’s production and revenues for each of the years ended December 31, 2013 and 2012 in exchange for shares of RSP Inc.’s common stock and cash. See “Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations: The IPO and Related Transactions - The Rising Star Acquisition” in our Annual Report on Form 10-K for the year ended December 31, 2015 for more information.

Overview and Outlook

Our financial and operating performance and significant events in 2016 include the following highlights:

- Increased our average daily production rate 33% for the second quarter of 2016 as compared to the same period in 2015, and 7% as compared to the first quarter of 2016.
- Decreased our cash operating costs on a per Boe basis 26% from $13.58 to $9.99 for the second quarter of 2016 as compared to the same period in 2015, and these costs were flat as compared to the first quarter of 2016. These costs include lease operating expense, production and ad valorem taxes, and general and administrative expense excluding equity based compensation expense.
- Reaffirmed our borrowing base under the credit facility at $600.0 million in May 2016.
- Acquired (with cash on hand) approximately $43.5 million of additional oil and gas properties in the Midland Basin.

Our average daily production rate during the second quarter of 2016 was 26,407 Boe/d, a 33% increase from our second quarter 2015 average daily production of 19,879 Boe/d, and a 7% increase from our first quarter 2016 average daily production of 24,615 Boe/d. Oil production was 73% of total production on a volumetric basis and 92% of our total revenues in the second quarter of 2016.

During the second quarter of 2016, we participated in the drilling of 20 horizontal wells (10 operated) and participated in the completion of 17 horizontal wells (11 operated). Two of the drilled operated horizontal wells noted above were included in a second quarter acquisition, in which we purchased and took over operations on these wells which were drilled but uncompleted. In our vertical drilling program, we completed 1 operated vertical well.

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

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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 anticipated 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.

Our open positions as of June 30, 2016 were as follows:

	Contracts expiring quarter ending:		
	September 30, 2016	December 31, 2016	Total
Crude Oil Collars:			
Notional volume (Bbl)	120,000	120,000	240,000
Weighted average ceiling price ($/Bbl)(1)	$ 74.41	$ 74.41	$ 74.41
Weighted average floor price ($/Bbl)(1)	$ 55.00	$ 55.00	$ 55.00
Weighted average short put price ($/Bbl)(1)	$ 45.00	$ 45.00	$ 45.00
Deferred Premium Puts:			
Notional volume (Bbl)	1,410,000	1,125,000	2,535,000
Weighted average floor price ($/Bbl)(1)	$ 45.00	$ 45.00	$ 45.00
Weighted average deferred premium ($/Bbl)	$ (2.59)	$ (2.74)	$ (2.65)

(1) The crude oil derivative contracts are settled based on the month’s average daily NYMEX price of West Texas Intermediate Light Sweet Crude.

2016 Capital Budget

The Company's updated capital budget for drilling, completion, and infrastructure for 2016 is approximately $285 to $315 million which anticipates operating three horizontal rigs for the second half of the third quarter and through the end of 2016. In addition, we plan on operating one dedicated completion crew for the rest of 2016. We will continue to monitor commodity prices, our cash flow and returns to determine any adjustments to our capital budget. We intend to complete a majority of our drilled but uncompleted well inventory in 2016, which will enable us to have a higher completion count than typically associated with our 2016 rig program.

Our 2016 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.

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Results of Operations

Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015

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 June 30,			
	2016	2015	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$74,799	$73,917	$882	1 %
Natural gas sales	2,537	2,028	509	25 %
NGL sales	4,149	2,520	1,629	65 %
Total revenues	$81,485	$78,465	$3,020	4 %
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$42.50	$53.68	$(11.18)	(21)%
Oil (per Bbl) (after impact of cash settled derivatives)	43.05	67.22	(24.17)	(36)%
Natural gas (per Mcf)	1.47	1.97	(0.50)	(25)%
Natural gas (per Mcf) (after impact of cash settled derivatives)	1.47	1.97	(0.50)	(25)%
NGLs (per Bbl)	11.69	9.69	2.00	21 %
Total (per Boe) (excluding impact of cash settled derivatives)	$33.91	$43.37	$(9.46)	(22)%
Total (per Boe) (after impact of cash settled derivatives)	$34.32	$53.68	$(19.36)	(36)%
Production:				
Oil (MBbls)	1,760	1,377	383	28 %
Natural gas (MMcf)	1,725	1,029	696	68 %
NGLs (MBbls)	355	260	95	37 %
Total (MBoe)	2,403	1,809	594	33 %
Average daily production volume:				
Total (Boe/d)	26,407	19,879	6,528	33 %

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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 Cushing, Oklahoma transport hub and the Gulf Coast 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 June 30,	
	2016	2015
Average realized oil price ($/Bbl)	$42.50	$53.68
Average NYMEX ($/Bbl)	45.59	57.94
Differential to NYMEX	(3.09)	(4.26)
Average realized oil price to NYMEX percentage	93%	93%
Average realized natural gas price ($/Mcf)	$1.47	$1.97
Average NYMEX ($/Mcf)	1.95	2.65
Differential to NYMEX	(0.48)	(0.68)
Average realized natural gas price to NYMEX percentage	75%	74%
Average realized NGL price ($/Bbl)	$11.69	$9.69
Average NYMEX oil price ($/Bbl)	45.59	57.94
Average realized NGL price to NYMEX oil price percentage	26%	17%

Our average realized oil price as a percentage of the average NYMEX price was 93% for both the three months ended June 30, 2016 and 2015. All of our oil contracts are impacted by the Midland-Cushing differential, which was a negative $0.17 per Bbl for the second quarter of 2016 and a negative $0.60 per Bbl in the comparable 2015 period.

Oil revenues increased 1% to $74.8 million for the three months ended June 30, 2016 from $73.9 million for the 2015 period as a result of an increase in oil production volumes of 383 MBbls, or 28%, partially offset by an $11.18 per Bbl decrease, or 21%, in our average realized price for oil.

Natural gas revenues increased 25% and were $2.5 million and $2.0 million for the three months ended June 30, 2016 and 2015, respectively. Natural gas production volumes increased by 696 MMcf, or 68%, which was partially offset by prices decreasing by $0.50 per Mcf, or 25%.

NGL revenues increased 65% to $4.1 million for the three months ended June 30, 2016 from $2.5 million for the 2015 period as a result of a $2.00 per Bbl increase, or 21%, in our average realized NGL price and an increase in NGL production volumes of 95 MBbls, or 37%.

Our higher production volumes for all products were primarily a result of increased production from our drilling program, along with the full period impact of our acquisitions closed in 2015.

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

	Three Months Ended June 30, 2016	2015	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$14,094	$14,693	$(599)	(4)%
Production and ad valorem taxes	4,960	5,402	(442)	(8)%
Depreciation, depletion and amortization	47,296	39,620	7,676	19 %
Asset retirement obligation accretion	123	84	39	46 %
Impairment of unproved properties	3,177	—	3,177	100 %
Exploration expense	405	889	(484)	(54)%
General and administrative expenses	9,135	6,865	2,270	33 %
Total operating expenses before loss (gain) on sale of assets	$79,190	$67,553	$11,637	17 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$5.37	$7.63	(2.26)	(30)%
Gathering and transportation	0.49	0.49	—	— %
Production and ad valorem taxes	2.06	2.99	(0.93)	(31)%
Depreciation, depletion and amortization	19.68	21.90	(2.22)	(10)%
Asset retirement obligation accretion	0.05	0.05	—	— %
Impairment	1.32	—	1.32	100 %
Exploration expense	0.17	0.49	(0.32)	(65)%
General and administrative - cash component	2.06	2.47	(0.41)	(17)%
General and administrative - recurring stock comp (1)	1.46	1.14	0.32	28 %
General and administrative - non-recurring stock comp (2)	0.28	0.19	0.09	47 %
Total operating expenses per Boe	$32.94	$37.35	$(4.41)	(12)%

(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) Non-recurring 2015 amounts include compensation expense related to the successful completion of the Company's IPO. These one-time awards vested over time for retention purposes. The non-recurring 2016 amount is a compensation charge associated with the retirement of an officer of the Company.

Lease Operating Expenses. Lease operating expenses decreased 4% to $14.1 million for the three months ended June 30, 2016 from $14.7 million for the 2015 period. The decrease was primarily attributable to increased operating efficiencies and cost reduction efforts in 2016. On a per Boe basis, lease operating expense, excluding gathering and transportation costs, decreased from $7.63 per Boe in 2015 to $5.37 per Boe in 2016. Gathering and transportation costs, which are included in lease operating expenses, were $1.2 million for the three months ended June 30, 2016 and $0.9 million for the 2015 period. On a per Boe basis, our gathering and transportation costs were $0.49 for both the three months ended June 30, 2016 and 2015.

Production and Ad Valorem Taxes. Production and ad valorem taxes decreased 8% to $5.0 million for the three months ended June 30, 2016 from $5.4 million for 2015, and decreased 31% on a per Boe basis to $2.06 per Boe for the three months ended June 30, 2016 mainly due to lower revenues per Boe.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (“DD&A”) expense increased 19% to $47.3 million for the three months ended June 30, 2016 from $39.6 million for the 2015 period mainly due to increased production. The DD&A rate decreased 10% to $19.68 per Boe for the three months ended June 30, 2016 from $21.90 per Boe for the 2015 period. The decrease in depletion per Boe in 2016 was due to an increase in our reserve volumes over the last year from acquisitions as well as successful drilling activities, somewhat offset by an increase in capitalized costs in proved property over the last year from these same activities.

Impairment of Unproved Properties. We incurred $3.2 million of impairment expense on our unproved property for the three months ended June 30, 2016. The impairment related to upcoming acreage lease expirations that the Company does not intend to develop. 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 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 Expense. Exploration expense decreased from $0.9 million for the three months ended June 30, 2015 to $0.4 million for the 2016 period due to less expenditures on geological and geophysical activity in 2016.

General and Administrative Expenses. General and administrative expenses increased to $9.1 million for the three months ended June 30, 2016, from $6.9 million for the 2015 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 $4.2 million for the three months ended June 30, 2016 and $2.4 million for the 2015 period. In the second quarter of 2016, the vesting on certain shares was accelerated which resulted in $0.7 million of additional equity-based compensation expense.

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

	Three Months Ended June 30,			
	2016	2015	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income, net	$104	$(37)	$141	(381)%
Net loss on derivative instruments	(3,684)	(12,962)	9,278	(72)%
Interest expense	(12,954)	(9,367)	(3,587)	38%
Total other income (expense)	$(16,534)	$(22,366)	$5,832	(26)%

Other Income. Other income was minimal for both the three months ended June 30, 2016 and 2015.

Net Loss on Derivative Instruments. During the three months ended June 30, 2016, we recorded a $3.7 million net loss as compared to a $13.0 million net loss in the 2015 period. The change was a result of expiring contracts on derivative positions over the last year and the future commodity price outlook as of June 30, 2016 as compared to June 30, 2015.

Interest Expense. During the three months ended June 30, 2016, we recorded $13.0 million of interest expense as compared to $9.4 million in the 2015 period. We expect our interest expense to remain higher than the prior-year period as a result of the issuance of additional senior notes in August 2015.

Income Tax Benefit. During the three months ended June 30, 2016, we recorded $4.4 million of income tax benefit compared to $6.0 million of income tax benefit in the 2015 period. The increase is a result of a larger pre-tax loss in the 2016 period.

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Results of Operations

Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015

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:

	Six Months Ended June 30,			
	2016	2015	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$126,490	$121,222	$5,268	4 %
Natural gas sales	4,940	4,261	679	16 %
NGL sales	5,871	4,356	1,515	35 %
Total revenues	$137,301	$129,839	$7,462	6 %
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$36.53	$49.38	$(12.85)	(26)%
Oil (per Bbl) (after impact of cash settled derivatives)	37.37	68.98	(31.61)	(46)%
Natural gas (per Mcf)	1.55	2.14	(0.59)	(28)%
Natural gas (per Mcf) (after impact of cash settled derivatives)	1.55	2.14	(0.59)	(28)%
NGLs (per Bbl)	9.07	9.53	(0.46)	(5)%
Total (per Boe) (excluding impact of cash settled derivatives)	$29.58	$40.02	$(10.44)	(26)%
Total (per Boe) (after impact of cash settled derivatives)	$30.21	$54.86	$(24.65)	(45)%
Production:				
Oil (MBbls)	3,463	2,455	1,008	41 %
Natural gas (MMcf)	3,190	1,989	1,201	60 %
NGLs (MBbls)	647	457	190	42 %
Total (MBoe)	4,642	3,244	1,398	43 %
Average daily production volume:				
Total (Boe/d)	25,505	17,923	7,582	42 %

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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 Cushing, Oklahoma transport hub and the Gulf Coast 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.

	Six Months Ended June 30,	
	2016	2015
Average realized oil price ($/Bbl)	$36.53	$49.38
Average NYMEX ($/Bbl)	39.52	53.29
Differential to NYMEX	(2.99)	(3.91)
Average realized oil price to NYMEX percentage	92 %	93 %
Average realized natural gas price ($/Mcf)	$1.55	$2.14
Average NYMEX ($/Mcf)	2.02	2.82
Differential to NYMEX	(0.47)	(0.68)
Average realized natural gas price to NYMEX percentage	77 %	76 %
Average realized NGL price ($/Bbl)	$9.07	$9.53
Average NYMEX oil price ($/Bbl)	39.52	53.29
Average realized NGL price to NYMEX oil price percentage	23 %	18 %

Our average realized oil price as a percentage of the average NYMEX price was 92% and 93% for the six months ended June 30, 2016 and 2015. All of our oil contracts are impacted by the Midland-Cushing differential, which was a negative $0.01 per Bbl for the first six months of 2016 and a negative $1.29 per Bbl in the comparable 2015 period.

Oil revenues increased 4% to $126.5 million for the six months ended June 30, 2016 from $121.2 million for the 2015 period as a result of an increase in oil production volumes of 1,008 MBbls, or 41%, partially offset by a $12.85 per Bbl decrease, or 26%, in our average realized price for oil.

Natural gas revenues increased 16% and were $4.9 million and $4.3 million for the six months ended June 30, 2016 and 2015, respectively. Natural gas prices production volumes increased by 1,201 MMcf, or 60%, partially offset by a decrease in natural gas prices of $0.59 per Mcf, or 28%.

NGL revenues increased 35% to $5.9 million for the six months ended June 30, 2016 from $4.4 million for the 2015 period as a result of an increase in NGL production volumes of 190 MBbls, or 42%, partially offset by a $0.46 per Bbl decrease, or 5%, in our average realized NGL price.

Our higher production volumes for all products were primarily a result of increased production from our drilling program, along with the full period impact of our acquisitions closed in 2015.

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

	Six Months Ended June 30,			
	2016	2015	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$27,185	$27,304	$(119)	— %
Production and ad valorem taxes	9,113	9,599	(486)	(5)%
Depreciation, depletion and amortization	91,855	71,121	20,734	29 %
Asset retirement obligation accretion	236	168	68	40 %
Impairment of unproved properties	3,350	—	3,350	100 %
Exploration expense	469	2,067	(1,598)	(77)%
General and administrative expenses	17,140	13,236	3,904	29 %
Total operating expenses before loss (gain) on sale of assets	$149,348	$123,495	$25,853	21 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$5.45	$7.89	(2.44)	(31)%
Gathering and transportation	0.40	0.53	(0.13)	(25)%
Production and ad valorem taxes	1.96	2.96	(1.00)	(34)%
Depreciation, depletion and amortization	19.79	21.92	(2.13)	(10)%
Asset retirement obligation accretion	0.05	0.05	—	— %
Impairment	0.72	—	0.72	100 %
Exploration expense	0.10	0.64	(0.54)	(84)%
General and administrative - cash component	2.12	2.68	(0.56)	(21)%
General and administrative - recurring stock comp (1)	1.42	1.15	0.27	23 %
General and administrative - non-recurring stock comp (2)	0.15	0.25	(0.10)	(40)%
Total operating expenses per Boe	$32.16	$38.07	$(5.91)	(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) Non-recurring 2015 amounts include compensation expense related to the successful completion of the Company's IPO. These one-time awards vested over time for retention purposes. The non-recurring 2016 amount is a compensation charge associated with the retirement of an officer of the Company.

Lease Operating Expenses. Lease operating expenses remained flat at $27.2 million for the six months ended June 30, 2016 from $27.3 million for the 2015 period despite a significant increase in production. On a per Boe basis, lease operating expense, excluding gathering and transportation costs, decreased from $7.89 per Boe in 2015 to $5.45 per Boe in 2016. The decrease was primarily attributable to higher production, increased operating efficiencies, and cost reduction efforts in the 2016 period. Gathering and transportation costs, which are included in lease operating expenses, were $1.9 million for the six months ended June 30, 2016 and $1.7 million for the 2015 period. On a per Boe basis, our gathering and transportation costs were $0.40 and $0.53 for the six months ended June 30, 2016 and 2015, respectively.

Production and Ad Valorem Taxes. Production and ad valorem taxes decreased 5% to $9.1 million for the six months ended June 30, 2016 from $9.6 million for 2015, and decreased 34% on a per Boe basis to $1.96 per Boe for the six months ended June 30, 2016 mainly due to lower revenues per Boe.

Depreciation, Depletion and Amortization. DD&A expense increased 29% to $91.9 million for the six months ended June 30, 2016 from $71.1 million for the 2015 period mainly due to increased production. The DD&A rate decreased 10% to $19.79 per Boe for the six months ended June 30, 2016 from $21.92 per Boe for the 2015 period. The decrease in depletion per Boe in 2016 was due to an increase in our reserve volumes over the last year from acquisitions as well as successful drilling activities, somewhat offset by an increase in capitalized costs in proved property over the last year from these same activities.

Impairment of Unproved Properties. We incurred $3.4 million of impairment expense on our unproved property for the six months ended June 30, 2016. The impairment related to upcoming acreage lease expirations that the Company does not intend

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to develop. 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 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 Expense. Exploration expense decreased from $2.1 million for the six months ended June 30, 2015 to $0.5 million for the 2016 period due to less expenditures on geological and geophysical activity in 2016.

General and Administrative Expenses. General and administrative expenses increased to $17.1 million for the six months ended June 30, 2016, from $13.2 million for the 2015 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 $7.3 million for the six months ended June 30, 2016 and $4.5 million for the 2015 period. In 2016, the vesting on certain shares was accelerated which resulted in $0.7 million of additional equity-based compensation expense.

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

	Six Months Ended June 30,			
	2016	2015	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income, net	$277	$161	$116	72 %
Net loss on derivative instruments	(3,288)	(631)	(2,657)	421 %
Interest expense	(25,895)	(18,683)	(7,212)	39 %
Total other income (expense)	$(28,906)	$(19,153)	$(9,753)	51 %

Other Income. Other income was minimal for both the six months ended June 30, 2016 and 2015.

Net Loss on Derivative Instruments. During the six months ended June 30, 2016, we recorded a $3.3 million net loss as compared to a $0.6 million net loss in the 2015 period. The change was a result of expiring contracts on derivative positions over the last year and the future commodity price outlook as of June 30, 2016 as compared to June 30, 2015.

Interest Expense. During the six months ended June 30, 2016, we recorded $25.9 million of interest expense as compared to $18.7 million in the 2015 period. We expect our interest expense to remain higher than the prior-year period as a result of the issuance of additional senior notes in August 2015.

Income Tax Benefit. During the six months ended June 30, 2016, we recorded $13.7 million of income tax benefit compared to $6.3 million of income tax benefit in the 2015 period. The increase is a result of a larger pre-tax loss in the 2016 period.

Capital Requirements and Sources of Liquidity

The Company's primary sources of liquidity have been proceeds from equity offerings, borrowings under the revolving credit facility, proceeds from the issuance of the senior notes, and cash flows from operations. To date, the Company's primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. At June 30, 2016, we had no borrowings outstanding under our revolving credit facility and our borrowing base was $600 million.

During the second quarter of 2016, we spent approximately $56.5 million on drilling and completion activities, $1.1 million of infrastructure and other, and $14.4 million on oil and natural gas property acquisitions. In the first six months of 2016, we incurred approximately $122.1 million on drilling and completion activities, $3.4 million on infrastructure and other, and $43.5 million on oil and natural gas property acquisitions.

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 2016 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 enter into. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, 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 be assured 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, totaled $4.9 million and $110.1 million at June 30, 2016 and December 31, 2015, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $32.9 million and $142.7 million at June 30, 2016 and December 31, 2015, 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 enter into. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil, NGL and natural gas production will be the largest variables affecting our working capital.

Contractual Obligations

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, 2015.

Off-Balance Sheet Arrangements

As of June 30, 2016, 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:

	Six Months Ended June 30,	
	2016	2015

	(In thousands)	
Net cash provided by operating activities	$65,449	$91,619
Net cash used in investing activities	(172,727)	(249,119)
Net cash (used in) provided by financing activities	(2,608)	145,263

Net cash provided by operating activities was approximately $65.5 million and $91.6 million for the six months ended June 30, 2016 and 2015, respectively. The decrease in net cash provided by operating activities for the six months ended June 30, 2016, as compared to the 2015 period, was primarily due a reduction in amounts received from our settled derivative contracts in the 2016 period.

Net cash used in investing activities was approximately $172.7 million and $249.1 million for the six months ended June 30, 2016 and 2015, respectively.

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Net cash used in financing activities was approximately $2.6 million for the six months ended June 30, 2016 and net cash provided by financing activities was approximately $145.3 million for the six months ended June 30, 2015. The 2015 period included $147.0 million of capital contributions received in follow-on stock offering.

Our Revolving Credit Facility

Our credit agreement has a borrowing base of $600 million, lenders' maximum facility commitments of $1.0 billion, and a maturity date of August 29, 2019. 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 notes, provided no default has occurred, and to allow RSP LLC to guarantee the existing 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. Our next borrowing base redetermination is scheduled for November 2016. As of June 30, 2016, we had no borrowings and $0.6 million of letters of credit outstanding under our revolving credit facility and $599.4 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.

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 three 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 (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 our revolving credit facility) for the four fiscal quarters then ended, of not greater than 4.5 to 1.0:
- a senior secured leverage ratio, which is the ratio of the sum of all the Company's debt that is (i) secured and (ii) not subordinated to obligations under the revolving credit facility to the consolidated EBITDAX (as defined in the credit agreement) for the four fiscal quarters then ended, of not greater than 3.5 to 1.0.

We were in compliance with such covenants and ratios as of June 30, 2016.

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 in Eurodollars 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 100 to 200 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 100 basis points; and (iii) the

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adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 0 to 100 basis points, depending on the percentage of our borrowing base utilized, plus a facility fee of 0.50% charged on the borrowing base amount. At June 30, 2016, the prime borrowing rate of interest under the Company's revolving credit facility was 3.50%. RSP LLC may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. As of June 30, 2016, the revolving credit facility has a margin of 1.00% to 2.00% plus LIBOR, plus a facility fee of 0.50% charged on the borrowing base amount.

Regulations

In June 2016, the SEC adopted a final rule that requires resource extraction issuers (“REIs”) to disclose information relating to any payment made by the REI to foreign governments or the U.S. government for the purpose of commercial development of oil, natural gas, or minerals. REIs will be required to comply with the final rule for fiscal years ending on or after September 30, 2018, and will be required to file a Form SD with the SEC within 150 days of a company's fiscal year-end. The Company is currently evaluating the impact of this final rule on its consolidated financial statements.

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.

Our open positions as of June 30, 2016 were as follows:

	Contracts expiring quarter ending:		
	September 30, 2016	December 31, 2016	Total
Crude Oil Collars:			
Notional volume (Bbl)	120,000	120,000	240,000
Weighted average ceiling price ($/Bbl)(1)	$ 74.41	$ 74.41	$ 74.41
Weighted average floor price ($/Bbl)(1)	$ 55.00	$ 55.00	$ 55.00
Weighted average short put price ($/Bbl)(1)	$ 45.00	$ 45.00	$ 45.00
Deferred Premium Puts:			
Notional volume (Bbl)	1,410,000	1,125,000	2,535,000

Weighted average floor price ($/Bbl)(1)	$45.00	$ 45.00	$ 45.00
Weighted average deferred premium ($/Bbl)	$(2.59)	$ (2.74)	$ (2.65)

(1) The crude oil derivative contracts are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude.

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The fair value of our derivative contracts as of June 30, 2016 was a net liability of $1.8 million. For information regarding the terms of these hedges, 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 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 June 30, 2016, we had no 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 June 30, 2016. 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 June 30, 2016 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 June 30, 2016 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, 2015, 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 June 30, 2016:

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
April 2016	154	$ 29.42	—	$ —
May 2016	863	$ 30.61	—	$ —
June 2016	27,119	$ 34.84	—	$ —
Total	28,136	$ 34.68	—	$ —

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

Item 6. Exhibits.

See Exhibit Index on page 37 of this Quarterly Report on Form 10-Q.

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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:	August 8, 2016

By:	/s/ Barry S. Turcotte
	Barry S. Turcotte
	Chief Accounting Officer
	(Principal Accounting Officer)
Date:	August 8, 2016

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EXHIBIT INDEX

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 Commission on January 29, 2014).
3.2	Amended and Restated Bylaws of RSP Permian, Inc. (incorporated by reference to Exhibit 3.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
4.1	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. 001-36273) filed with the Commission on January 29, 2014).
4.2	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. 001-36273) filed with the Commission on January 29, 2014).
4.3	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 Commission on October 2, 2014).
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.