RSP Permian, Inc.
Form 10-Q
August 04, 2015

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, 2015

or

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

For the transition period from to

Commission File Number: 001-36264

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

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

(214) 252-2700

(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Registration S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x (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 84,020,102 shares of common stock outstanding at July 31, 2015.

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GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

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

“Bbl.” A standard barrel containing 42 U.S. gallons.

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

“Boe/d.” One Boe per day.

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

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

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

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

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

“Dry natural gas.” A natural gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.

“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.

“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.

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“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.

“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.

“We,” “our,” “us” or like terms and the “Company” and "RSP" refer to, prior to the transactions, RSP Permian, L.L.C. and, after the IPO Transactions (as defined in “Part I, Item 1. Business-History and Formation” in our Annual Report on Form 10-K for the year ended December 31, 2014), to RSP Permian, Inc. and its subsidiary, RSP Permian, L.L.C.

“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.

Information presented in this Quarterly Report on Form 10-Q on a pro forma basis gives effect to the completion of the corporate reorganization and acquisitions in connection with our initial public offering completed in January 2014, each as described under “Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operation—The IPO and Related Transactions.”

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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. 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, 2014.

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, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$44,055	$56,292
Accounts receivable	61,757	40,436
Derivative instruments	28,461	76,990
Current deferred income taxes	4,767	—
Other assets	24	24
Total current assets	139,064	173,742
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	2,482,979	2,240,803
Accumulated depletion	(241,372)	(171,046)
Total oil and natural gas properties, net	2,241,607	2,069,757
Other property and equipment, net	29,681	24,861
Total property, plant and equipment	2,271,288	2,094,618
OTHER LONG-TERM ASSETS		
Derivative instruments	1,031	—
Restricted cash	152	152
Other long-term assets	22,118	21,435
Total long-term assets	23,301	21,587
TOTAL ASSETS	$2,433,653	$2,289,947
LIABILITIES AND STOCKHOLDERS’ EQUITY		
CURRENT LIABILITIES		
Accounts payable	$22,946	$35,728
Accrued expenses	73,900	57,977
Interest payable	8,653	9,227
Deferred taxes	9,225	25,789
Derivative instruments	1,291	1,320
Total current liabilities	116,015	130,041
LONG-TERM LIABILITIES		
Asset retirement obligations	5,388	4,873
Derivative instruments	1,279	—
Long-term debt	500,000	500,000
Deferred taxes	341,872	329,262
Total long-term liabilities	848,539	834,135
Total liabilities	964,554	964,176
STOCKHOLDERS' EQUITY		
Common stock, $.01 par value; 300,000,000 shares authorized, 84,020,222 shares issued and outstanding at June 30, 2015; 77,903,834 shares issued and outstanding at December 31, 2014	840	779

Additional paid-in capital	1,472,239	1,322,494
Retained earnings	(3,980)	2,498
Total stockholders' equity	1,469,099	1,325,771
TOTAL LIABILITIES AND STOCKHOLDERS’ EQUITY	$2,433,653	$2,289,947

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,	
	2015	2014	2015	2014
REVENUES				
Oil sales	$73,917	$66,134	$121,222	$117,606
Natural gas sales	2,028	3,117	4,261	5,323
NGL sales	2,520	4,811	4,356	8,892
Total revenues	78,465	74,062	129,839	131,821
OPERATING EXPENSES				
Lease operating expenses	$14,693	$9,279	$27,304	$16,342
Production and ad valorem taxes	5,402	5,964	9,599	9,840
Depreciation, depletion and amortization	39,620	21,734	71,121	38,096
Asset retirement obligation accretion	84	38	168	66
Exploration expenses	889	1,233	2,067	1,989
General and administrative expenses	6,865	5,238	13,236	22,254
Total operating expenses	67,553	43,486	123,495	88,587
OPERATING INCOME	$10,912	$30,576	$6,344	$43,234
OTHER INCOME (EXPENSE)				
Other income (expense), net	$(37)	$(302)	$161	$8
Loss on derivative instruments	(12,962)	(15,958)	(631)	(20,111)
Interest expense	(9,367)	(1,142)	(18,683)	(2,272)
Total other income (expense)	(22,366)	(17,402)	(19,153)	(22,375)
INCOME (LOSS) BEFORE TAXES	(11,454)	13,174	(12,809)	20,859
INCOME TAX (EXPENSE) BENEFIT	6,001	(4,948)	6,331	(140,162)
NET INCOME (LOSS)	$(5,453)	$8,226	$(6,478)	$(119,303)
Income (loss) per common share:				
Basic	$(0.07)	$0.11	$(0.08)	$(1.76)
Diluted	$(0.07)	$0.11	$(0.08)	$(1.76)
Weighted average shares outstanding:				
Basic	83,088	72,500	80,639	67,702
Diluted	83,088	72,500	80,639	67,702

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	Retained Earnings	Total Stockholders' Equity
BALANCE AT DECEMBER 31, 2014	77,904	$779	$1,322,494	$2,498	$1,325,771
Shares of common stock issued in public offerings net of offering costs	5,750	58	146,990	—	147,048
Retirement of common stock	(67)	(1)	(1,784)	—	(1,785)
Equity-based compensation	433	4	4,539	—	4,543
Net loss	—	—	—	(6,478)	(6,478)
BALANCE AT JUNE 30, 2015	84,020	840	1,472,239	(3,980)	1,469,099

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, 2015	2014
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$(6,478)	$(119,303)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	71,121	38,096
Accretion of asset retirement obligations	168	66
Equity based compensation	4,543	13,679
Amortization of loan fees	978	423
Deferred income taxes	(3,954)	138,486
Equity in loss of investment	74	—
Loss on derivative instruments	631	20,111
Net cash receipts (payments) on settled derivatives	48,286	(1,828)
Changes in operating assets and liabilities:		
Accounts receivable and accounts receivable from related parties	(26,256)	(3,371)
Other assets	(60)	4,838
Accounts payable	(12,782)	9,865
Accrued expenses	15,923	(4,010)
Interest payable	(575)	41
Net cash provided by operating activities	$91,619	$97,093
CASH FLOWS FROM INVESTING ACTIVITIES		
Additional investment in unconsolidated subsidiary	(1,675)	—
Additions to other property and equipment	(5,369)	(1,740)
Additions to oil and natural gas properties	(242,075)	(268,886)
Net cash used in investing activities	$(249,119)	$(270,626)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of common stock	147,048	163,082
Distributions	—	(1,663)
Payments of debt issuance costs	—	(232)
Borrowings under long-term debt	15,000	140,000
Payments on long-term debt	(15,000)	(126,155)
Repurchase and retirement of common stock	(1,785)	—
Net cash provided by financing activities	$145,263	$175,032
NET CHANGE IN CASH	$(12,237)	$1,499
CASH AT BEGINNING OF PERIOD	$56,292	$13,234
CASH AT END OF PERIOD	$44,055	$14,733
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash paid for interest	$18,279	$1,808
Cash paid for taxes	$2,700	$—
NON-CASH ACTIVITIES		
Asset retirement obligation acquired	$—	2,412
Change in accrued capital expenditures	$13,661	$14,442
Common stock issued for oil and gas properties	$—	677,402
Deferred tax liabilities recorded for oil and gas property acquisitions	$—	195,777

Elimination of NPI payable	$—	36,931

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

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NOTE 1—NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Organization and Description of the Business

RSP Permian, Inc. ("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.

Recent Developments

On March 23, 2015, RSP Inc. completed an underwritten public offering, by RSP Inc. and certain of its shareholders, of 9.0 million shares of RSP Inc. common stock at $25.80 per share. The Company sold 5.0 million primary shares in the offering raising $127.9 million in net proceeds. On April 10, 2015, the underwriter exercised its option to purchase an additional 1.35 million shares, providing an additional $19.2 million in net proceeds to the Company. Additional background on the Company and 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, 2014.

Basis of Presentation

These 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. 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, 2014, which contains a summary of the Company's significant accounting policies and disclosures.

Subsequent Events

The Company has evaluated subsequent events in preparing the consolidated financial statements. The Company has recently closed or entered into definitive purchase agreements to acquire undeveloped acreage and oil and gas producing properties located in Martin and Glasscock counties for an aggregate purchase price of approximately $274 million, subject to certain purchase price adjustments. The aggregate acquisitions include 5,704 net acres, with an average royalty burden of approximately 23%, in our core focus areas with current production of approximately 1,569 Boe/d and 162 net horizontal drilling locations. Approximately $65 million of the acquisitions have been funded through cash on hand and $50 million drawn on the Company’s revolving credit facility; and the Company intends to finance the remaining acquisitions, subject to market conditions and other factors, with proceeds from one or more capital market transactions, which may include debt or equity offerings. In the absence of capital markets transactions, the Company intends to fund the acquisitions with remaining availability under its revolving credit facility. However, the remaining transactions remain subject to the completion of due diligence and satisfaction of other closing conditions. There can be no assurances that the Company will close on all or any portion of the remaining acquisitions.

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 and the fair value of incentive unit compensation 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

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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

	As of June 30, 2015	As of December 31, 2014
	(In thousands)	
Sale of oil and natural gas and related products	$31,296	$24,059
Accounts receivable from unconsolidated affiliate	5,903	—
Joint interest owners	18,750	10,400
Derivatives - settled, but uncollected	5,808	5,977
Total accounts receivable	$61,757	$40,436

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. As of June 30, 2015, accounts receivable also includes an amount due from affiliate related to a water service well drilled by the Company on behalf of the affiliate. 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 Company has provided an allowance for doubtful accounts based on management’s expectations that all material receivables at period-end will be collected. The need for an allowance is determined based upon reviews of individual accounts, historical losses, existing economic conditions and other pertinent factors. Bad debt expense was zero for the three and six months ended June 30, 2015 and 2014, 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 while activities are in progress to bring the assets to their intended use for significant exploration and development projects that last more than six months. 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. Unproved properties are assessed at least annually for possible impairment.

Capitalized acquisition costs attributable to proved oil and natural gas properties and leasehold costs are depleted on a field basis based on proved reserves using the unit-of-production method. Capitalized exploration well costs and development costs, including AROs, are depleted on a field basis, based on proved developed reserves. For the three months ended June 30, 2015 and 2014, depletion expense for oil and natural gas producing property was $39.3 million and $21.6 million, respectively. For the six months ended June 30, 2015 and 2014, depletion expense for oil and natural gas producing property was $70.3 million and $37.9 million. 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, 2015 and December 31, 2014 consisted of the following:

	June 30, 2015	December 31, 2014
	(In thousands)	
Proved oil and natural gas properties	$1,869,970	$1,585,125
Unproved oil and natural gas properties	613,009	655,678
Total oil and natural gas properties	2,482,979	2,240,803
Less: Accumulated depletion	(241,372)	(171,046)
Total oil and natural gas properties, net	$2,241,607	$2,069,757

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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, 2015 and December 31, 2014, 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 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 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. Unproved properties are assessed at least annually to determine whether they have been impaired. An impairment allowance is provided on an unproved property when the Company determines that the property will not be developed. 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 three or six months ended June 30, 2015 or 2014.

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, 2015

	(In thousands)
Asset retirement obligation at beginning of period	$4,873
Liabilities assumed	347
Accretion expense	168
Asset retirement obligation at end of period	$5,388

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Income Taxes

RSP LLC was organized as a limited liability company and treated as a flow-through entity for federal income tax purposes. As such, taxable income and any related tax credits were passed through to its members and are included in their tax returns even though such net taxable income or tax credits may not have actually been distributed. Accordingly, provision for federal and state corporate income taxes has been made only for the operations of RSP Inc. beginning on January 23, 2014 in the accompanying consolidated financial statements. Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. Upon the corporate reorganization in connection with the IPO transaction, the Company established a $132 million deferred income tax liability, which was recognized as tax expense from continuing operations in the first quarter of 2014. This $132 million deferred income tax liability, related to our change in tax status, was subsequently adjusted to $95 million during the fourth quarter of 2014. The primary upward adjustments in the effective tax rate for 2014 shown above the U.S. statutory rate are the adjustment for the corporate reorganization noted above along with non-deductible incentive unit compensation. The primary upward adjustment in the effective tax rate for 2015 shown above the U.S. statutory rate is the adjustment to reduce the Texas margins tax from 1.0% to 0.75% in the second quarter of 2015.

The following is an analysis of the Company’s consolidated income tax expense:

	Three Months Ended June 30,		Six Months Ended June 30	
	2015	2014	2015	2014
	(In thousands)		(In thousands)	
Current	$(3,561)	$805	$(2,377)	$1,676
Deferred	(2,440)	4,143	(3,954)	138,486
Income Tax Expense (Benefit)	$(6,001)	$4,948	$(6,331)	$140,162

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, 2015, 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 April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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. An entity is required to apply ASU 2015-03 for annual and interim reporting periods beginning after December 15, 2015. The Company is evaluating the impact that this new guidance will have on its consolidated financial statements.

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 Company does not expect the impact of its pending adoption of this guidance will have a material effect 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

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initially applying the standard is recognized in the most current period presented in the financial statements. The Company does not expect the impact of its pending adoption of this guidance will have a material effect on its consolidated financial statements.

NOTE 3—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 over-the-counter ("OTC") swaps, collars, and collars with short puts. 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 swap transaction has an established fixed price. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

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.

The following table summarizes all open positions as of June 30, 2015:

Contracts Expiring in 2015	
Crude Oil Swaps:	
Notional volume (Bbl)	60,000
Weighted average price ($/Bbl)(1)	$92.60
Crude Oil Collars:	
Notional volume (Bbl)	996,000
Weighted average ceiling price ($/Bbl)(1)	$94.30
Weighted average floor price ($/Bbl)(1)	$85.57
Contracts Expiring in 2016	
Crude Oil Collars:	
Notional volume (Bbl)	555,000
Weighted average ceiling price ($/Bbl)(1)	$74.08
Weighted average floor price ($/Bbl)(1)	$55.00
Weighted average short put price ($/Bbl)(1)	$45.00

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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.

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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 4 for further discussion related to the fair value of the Company's derivatives.

	Assets		Liabilities	
	June 30, 2015	December 31, 2014	June 30, 2015	December 31, 2014
	(In thousands)			
Derivative Instruments:				
Current amounts				
Commodity contracts	$28,461	$ 76,990	$(1,291)	$ (1,320)
Noncurrent amounts				
Commodity contracts	1,031	—	(1,279)	—
Total derivative instruments	$29,492	$ 76,990	$(2,570)	$ (1,320)

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In thousands)		(In thousands)	
Loss on derivative instruments:				
Commodity derivative instruments	$(12,962)	$(15,958)	$(631)	$(20,111)
Total	$(12,962)	$(15,958)	$(631)	$(20,111)

Offsetting of Derivative Assets and Liabilities

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

	Gross Amount Presented on Balance Sheet	Netting Adjustments(a)	Net Amount
	(In thousands)		
June 30, 2015			
Derivative instrument assets with right of offset or master netting agreements	$29,492	$ (2,570)	$26,922
Derivative instrument liabilities with right of offset or master netting agreements	$(2,570)	$ 2,570	$—
December 31, 2014			
Derivative instrument assets with right of offset or master netting agreements	$76,990	$ (1,320)	$75,670
Derivative instrument liabilities with right of offset or master netting agreements	$(1,320)	$ 1,320	$—

(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, 2015 and December 31, 2014.

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NOTE 4—FAIR VALUE MEASUREMENTS

The book values of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate fair value due to the short-term nature of these instruments. The book value of the Company’s 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 we 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, 2015:				
Commodity derivative instruments	$—	$26,922	$—	$26,922
Total	$—	$26,922	$—	$26,922

	Level 1	Level 2	Level 3	Total fair value
	(In thousands)			
As of December 31, 2014:				
Commodity derivative instruments	$—	$75,670	$—	$75,670
Total	$—	$75,670	$—	$75,670

Significant Level 2 assumptions used to measure the fair value of the commodity derivative instruments include current market and contractual commodity prices, 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 three or six months ended June 30, 2015 and the year ended December 31, 2014.

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 5—LONG-TERM DEBT

Long-term debt consists of the following:

	June 30, 2015	December 31, 2014
	(In millions)	
6.625% Senior notes	$500.0	$500.0
Total long-term debt	$500.0	$500.0

Credit Agreement

In conjunction with the closing of our acquisitions in Glasscock County, on August 29, 2014, the Company amended the revolving credit facility to increase the borrowing base to $500 million, to increase the lenders’ maximum facility commitments to $1.0 billion, to extend the maturity date to August 29, 2019 and to allow the Company to issue the senior unsecured notes described below. In connection with the Company's issuance of its senior unsecured notes, on September 24, 2014, the Company amended the revolving credit facility to permit RSP LLC to make payment to the Company to enable it to pay principal, premium (if any) and interest on the unsecured notes provided no default has occurred and to allow RSP LLC to guaranty the unsecured notes.

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,
•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

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specified percentage of its outstanding indebtedness, incur liens, sell assets or engage in certain other transactions without the prior consent of the lenders.

The Company was in compliance with such covenants and ratios as of June 30, 2015.

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, 2015, the prime borrowing rate of interest under the Company’s revolving credit facility was 3.25%. 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, 2015, 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.

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 $500 million as of June 30, 2015, 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. 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 and commenced on April 1, 2015. 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 notes, which is included in “Other long-term assets” 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 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, 2015.

NOTE 6—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.

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Environmental Matters

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

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

Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At both June 30, 2015 and December 31, 2014, 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, 2014.

NOTE 7—EQUITY-BASED COMPENSATION

Equity-based compensation expense, which was recorded in General and administrative expenses, was $2.4 million and $1.7 million for the three months ended June 30, 2015 and 2014, respectively. This same expense was $4.5 million and $13.7 million for the six months ended June 30, 2015 and 2014, respectively. Equity-based compensation expense in the 2014 period includes expense related to incentive units. Expenses related to incentive units are described in more detail below. Incentive unit expense was $0.2 million and $11.4 million for the three months and six months ended June 30, 2014, 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 $1.6 million and $1.3 million for the three months ended June 30, 2015 and 2014, respectively. This same expense was $3.2 million and $2.1 million for the six months ended June 30, 2015 and 2014, respectively. The Company views restricted stock awards with graded vesting as single awards with an expected life equal to the average expected life and amortize the awards on a straight-line basis over the life of the awards.

The compensation expense for these awards was determined based on the market price of the Company’s common stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of June 30, 2015, the Company had unrecognized compensation expense of $11.0 million related to restricted stock awards which is expected to be recognized over a weighted average period of 2.0 years.

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

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	Six Months Ended June 30, 2015 Shares	Weighted Average Fair Value	2014 Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	477,767	$23.71	—	$—
Restricted shares granted	277,510	27.19	463,951	23.51
Restricted shares canceled	(4,289)	26.07		
Restricted shares vested	(243,274)	22.84	—	—
Restricted shares outstanding, end of period	507,714	$26.01	463,951	$23.51

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.

Equity-based compensation for these awards was $0.8 million and $0.1 million for the three months ended June 30, 2015 and 2014, respectively. This same expense was $1.3 million and $0.1 million for the six months ended June 30, 2015 and 2014, respectively. The compensation expense for the market conditions is based on a per share value using a Monte-Carlo simulation. The unrecognized compensation expense related to these shares is approximately $7.1 million as of June 30, 2015 and is expected to be recognized over the next 2.12 years. 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 following table represents performance-based restricted stock award activity for the six months ended June 30:

	Six Months Ended June 30, 2015 Shares	Weighted Average Fair Value	2014 Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	134,400	$28.14	—	$—
Restricted shares granted	159,932	31.74	134,400	28.14
Restricted shares outstanding, end of period	294,332	$31.41	134,400	$28.14

Incentive Units

Pursuant to the LLC Agreement of RSP LLC, certain incentive units were available to be issued to the Company's management and employees. After successful completion of the IPO, the performance conditions associated with certain incentive units were deemed probable of reaching payout. For the three and six months ended June 30, 2014, the Company recognized non-cash compensation expense of $0.2 million and $11.4 million, respectively, related to these incentive units. In December 2014, the incentive unit plan was concluded and all awards remaining under the incentive unit plans were allocated according to performance criteria established at the adoption of the plan. These incentive units determined the stock allocation of shares held by RSP Permian Holdco, between management and NGP and had no dilutive impact, or cash impact, to shareholders of RSP Permian, Inc. In periods subsequent to 2014, there will be no additional expense recognized related to these incentive units.

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NOTE 8—EARNINGS PER SHARE & PRO FORMA EARNINGS PER SHARE

Earnings per Share

The Company's basic earnings per share amounts have been computed using the two-class method based on the weighted-average number of shares of common stock outstanding for the period. Because the Company recognized a net loss for the three months ended June 30, 2015, the six months ended June 30, 2015, and the six months ended June 30, 2014, unvested restricted share awards were not recognized in dilutive 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,	
	2015	2014
	(In thousands)	
Numerator:		
Net income available to stockholders	$(5,453)	$8,226
Basic net income allocable to participating securities (1)	—	49
Income available to stockholders	$(5,453)	$8,177
Denominator:		
Weighted average number of common shares outstanding - basic	83,088	72,500
Effect of dilutive securities:		
Restricted stock	—	—
Weighted average number of common shares outstanding - diluted	83,088	72,500
Net loss per share:		
Basic	$(0.07)	$0.11
Diluted	$(0.07)	$0.11

(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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	Six Months Ended June 30, 2015	2014
	(In thousands)	
Numerator:		
Net income (loss) available to stockholders	$(6,478)	$(119,303)
Basic net income (loss) allocable to participating securities (1)	—	—
Income (loss) available to stockholders	$(6,478)	$(119,303)
Denominator:		
Weighted average number of common shares outstanding - basic	80,639	67,702
Effect of dilutive securities:		
Restricted stock	—	—
Weighted average number of common shares outstanding - diluted	80,639	67,702
Net income (loss) per share:		
Basic	$(0.08)	$(1.76)
Diluted	$(0.08)	$(1.76)

(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.

Pro Forma Earnings per Share

The Company computed a pro forma income tax provision as if the Company was subject to income taxes since January 1, 2014. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, and excludes the non-recurring tax adjustment related to the corporate reorganization of the Company on January 23, 2014, as further described in Note 2 under “Income Taxes.”

The Company’s pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued in the IPO were outstanding since January 1, 2014. A reconciliation of the components of pro forma basic and diluted earnings per common share is presented in the table below:

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	Six Months Ended June 30, 2014
Numerator:	
Income before taxes, as reported	$20,859
Pro forma provision for income taxes	7,509
Pro forma net income available to stockholders	13,350
Basic net income allocable to participating securities	82
Pro forma net income available to stockholders	$13,268
Denominator:	
Weighted average number of common shares outstanding - basic	72,500
Effect of dilutive securities:	
Restricted stock	—
Weighted average number of common shares outstanding - diluted	72,500
Net income per share:	
Basic	$0.18
Diluted	$0.18

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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, 2014.

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, 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, which 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, became a wholly owned subsidiary of RSP Inc. See "-The IPO and Related Transactions-Corporate Reorganization" 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 "-The IPO and Related Transactions-The Rising Star Acquisition" for more information.

Overview and Outlook

Our financial and operating performance and significant events in 2015 included the following highlights:

- Increased our average daily production rate 86% for the six months ended June 30, 2015 as compared to the same period in 2014.
- In March 2015, we completed a follow-on underwritten public offering of 9.0 million shares of our common stock, with 5.0 million shares sold by RSP Inc., resulting in approximately $127.9 million of net proceeds. In April 2015, the underwriters exercised their option to purchase all of their option shares which provided additional proceeds to the Company of $19.2 million.
- In May 2015, the borrowing base of our revolving credit facility was re-determined at the current level of $500 million. The credit facility matures on August 29, 2019 and includes maximum lender commitments of $1 billion.
- Subsequent to the end of the second quarter of 2015, he Company has closed or entered into definitive purchase agreements to acquire undeveloped acreage and oil and gas producing properties located in Martin and Glasscock counties for an aggregate purchase price of approximately $274 million, subject to certain purchase price adjustments. The aggregate acquisitions include 5,704 net acres, with an average royalty burden of approximately 23%, in our core focus areas with current production of approximately 1,569 Boe/d and 162 net horizontal drilling locations. Approximately $65 million of the acquisitions have been funded through cash on hand and $50 million drawn on the Company's revolving credit facility; and the Company intends to finance the remaining acquisitions, subject to market conditions and other factors, with proceeds from one or more capital market transactions, which may include debt or equity offerings. In the absence of capital markets transactions, the Company intends to fund the acquisitions with remaining availability under its revolving credit facility. However, the remaining transactions remain subject to the completion of due diligence and satisfaction of other closing conditions. There can be no assurances that the Company will close on all or any portion of the remaining acquisitions.

Our average daily production rate during the second quarter of 2015 was 19,879 Boe/d, an 86% increase from our second quarter 2014 average daily production of 10,714 Boe/d, and a 25% increase from our first quarter 2015 average daily production of 15,944 Boe/d. Oil production was 76% of total production on a volumetric basis and 94% of our total revenues in the second quarter of 2015.

During the second quarter of 2015, we drilled 27 horizontal wells (13 operated) and completed 29 horizontal wells (18 operated). In our vertical drilling program, we drilled 4 vertical wells (1 operated), and completed 14 vertical wells (11 operated). For the second half of 2015, we anticipate operating four horizontal rigs with three of the drilling rigs under contract and one horizontal rig operating on a well by well arrangement enabling the Company flexibility to drop the fourth rig.

How We Evaluate Our Operations

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

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

Due to the inherent volatility in commodity prices, we have historically used commodity derivative instruments, such as collars, swaps and puts, to hedge price risk associated with a significant portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in commodity prices and provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in commodity prices and may partially limit our potential gains from future increases in prices. None of our instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge a portion of our physical production in order to protect our returns. Our revolving credit facility limits our ability to enter into commodity hedges covering greater than 85% of our reasonably 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, 2015 were as follows:

Description & Production Period	Volume (Bbls)	Weighted Average Floor price ($/Bbl)(1)	Weighted Average Ceiling price ($/Bbl)(1)	Weighted Average Short Put price ($/Bbl)(1)	Weighted Average Swap price ($/Bbl)(1)
Crude Oil Swaps:					
July 2015 — December 2015	60,000				$92.60
Crude Oil Collars:					
July 2015 — December 2015	816,000	$85.70	$94.71		
July 2015 — September 2015	90,000	$85.00	$92.60		
October 2015 — December 2015	90,000	$85.00	$92.33		
January 2016 — March 2016	75,000	$55.00	$72.00	$45.00	
January 2016 — December 2016	480,000	$55.00	$74.41	$45.00	

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

The IPO and Related Transactions

The historical results of operations prior to our IPO are based on the financial statements of our predecessor, which reflects the combined results of RSP LLC and Rising Star Energy Development Co., L.L.C. ("Rising Star"). In January 2014, we successfully completed our IPO, and in connection with our IPO, we completed the transactions described below, which changed our structure and increased the scope of our operations.

Corporate Reorganization. Pursuant to the terms of a corporate reorganization, (i) the members of RSP LLC contributed all of their interests in RSP LLC to RSP Permian Holdco, L.L.C., a newly formed entity that is wholly owned by such members, and (ii) RSP Permian Holdco, L.L.C. contributed all of its interests in RSP LLC to RSP

Permian, Inc. in exchange for approximately 28.5 million shares of common stock of RSP Inc., an assignment of RSP LLC's pro rata share of an escrow related to a disposition by RSP LLC of working interests and the right to receive approximately $27.7 million in cash. As a result of the reorganization, RSP LLC became a wholly owned subsidiary of RSP Inc.

The Rising Star Acquisition. In connection with our IPO, we acquired from Rising Star working interests (the "Rising Star Assets") in certain acreage and wells in the Permian Basin in which RSP LLC already had working interests (the "Rising Star Acquisition"). In exchange, Rising Star received approximately 1.8 million shares of RSP Inc.'s common stock and the right to receive approximately $1.7 million in cash. The Rising Star Acquisition increased our average working interest in

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approximately 3,250 gross acres and 36 gross producing wells in the Permian Basin. The Rising Star Assets represented substantially all of Rising Star’s production and revenues for the years ended December 31, 2013 and 2012.

The Collins and Wallace Contributions. Ted Collins, Jr. ("Collins"), Wallace Family Partnership, LP ("Wallace LP) and Collins & Wallace Holdings, LLC contributed to us certain working interests in certain of RSP LLC’s existing properties in the Permian Basin. In exchange, (i) Collins received approximately 9.9 million shares of RSP Inc.’s common stock and the right to receive approximately $1.6 million in cash, (ii) Wallace LP received approximately 10.0 million shares of RSP Inc.’s common stock and the right to receive approximately $0.6 million in cash, and (iii) Collins & Wallace Holdings, LLC received approximately 2.2 million shares of RSP Inc.’s common stock.

The Pecos Contribution. Pecos Energy Partners, L.P. ("Pecos"), an entity owned by certain members of our management team, contributed to us certain working interests in certain acreage and wells in the Permian Basin in which RSP LLC already had working interests. In exchange, Pecos received approximately 0.1 million shares of RSP Inc.’s common stock. Pecos’s contribution increased our working interests in approximately 650 gross acres and six producing wells.

The ACTOIL NPI Repurchase. In July 2011, RSP LLC sold to ACTOIL, LLC ("ACTOIL") a 25% net profits interest (“NPI”) in substantially all of our oil and natural gas properties taken as a whole. In addition, in connection with RSP LLC’s acquisition of additional working interests in certain of its existing properties (the “Spanish Trail Assets”) in September 2013 (the “Spanish Trail Acquisition”), RSP LLC sold to ACTOIL a 25% NPI in the Spanish Trail Assets. Subsequent to our sale to ACTOIL of the NPIs, the oil and natural gas properties that underpinned ACTOIL’s NPIs remained owned and controlled by us. The NPIs entitled ACTOIL to 25% of the relevant properties’ cumulative revenues in excess of their cumulative direct operating expenses and capital expenditures. In connection with the IPO, ACTOIL contributed both 25% NPIs to us (the “ACTOIL NPI Repurchase”) in exchange for approximately 10.8 million shares of RSP Inc.’s common stock.

2015 Capital Budget

Our board of directors has approved a capital budget for drilling, completion, and infrastructure for 2015 of approximately $400 to $450 million. We have the capacity to fund our 2015 capital expenditures with expected cash generated by operations and borrowings under our revolving credit facility. Historically, the Company has used the debt and equity capital markets to sell securities to fund a portion of its operations. The Company continually reviews various capital markets transactions as a source of funding for its capital program. We intend to allocate our 2015 capital budget (which excludes acquisitions) approximately as follows:

- $380 to $420 million for drilling and completion activities, approximately 15% of which is non-operated drilling and completion activities; and
- $20 to $30 million for infrastructure and other.

Pro Forma Quarterly Financial Data

The below pro forma information for the six months ended June 30, 2014 was derived from our actual results and has been adjusted to reflect the Collins and Wallace Contributions and the ACTOIL NPI Repurchase, both of which were completed in connection with the IPO on January 23, 2014, as if such transactions had occurred on January 1, 2014. The below pro forma information for the six months ended June 30, 2014 also reflects adjustments for non-recurring expenses associated with the IPO.

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The pro forma financial information included below does not give effect to certain acquisitions that were immaterial to our actual and pro forma results for the periods reflected below.

	RSP Permian, Inc.		RSP Permian, Inc. Pro Forma
	Six Months Ended June 30,		
	2015	2014	2014
Production data:			
Oil (MBbls)	2,455	1,231	1,281
Natural gas (MMcf)	1,989	1,285	1,333
NGLs (MBbls)	457	302	313
Total (MBoe)	3,244	1,747	1,816
Average net daily production (Boe/d)	17,923	9,652	10,033
Average prices before effects of hedges(1)(2):			
Oil (per Bbl)	$49.38	$95.54	$ 95.29
Natural gas (per Mcf)	2.14	4.14	4.14
NGLs (per Bbl)	9.53	29.44	29.48
Total (per Boe)	$40.02	$75.46	$ 75.33
Average realized prices after effects of hedges(1)(2):			
Oil (per Bbl)	$68.98	$93.29	$ 93.13
Natural gas (per Mcf)	2.14	4.14	4.14
NGLs (per Bbl)	9.53	29.44	29.48
Total (per Boe)	$54.86	$73.87	$ 73.81
Average costs (per Boe):			
Lease operating expenses (excluding gathering and transportation)	$7.89	$8.59	$ 8.62
Gathering and transportation	0.53	0.76	0.76
Production and ad valorem taxes	2.96	5.63	5.56
Depreciation, depletion and amortization	21.92	21.81	22.99
Components of general and administrative expense:			
General and administrative - cash component	$2.68	$4.91	$ 2.94
General and administrative - (non IPO stock comp)	1.15	0.54	0.52
General and administrative - (IPO stock comp)	0.25	7.29	—
Total general and administrative	$4.08	$12.74	$ 3.46

(1) Average prices shown in the table reflect prices both before and after the effects of our cash payments/receipts on our commodity derivative transactions. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivative transactions and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments settled in the period if applicable.

(2) Average realized prices for oil are net of transportation costs. Average realized prices for natural gas do not include transportation costs; instead, transportation costs related to our gas production and sales are included in our lease operating expenses. No transportation costs are associated with NGL production and sales.

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	RSP Permian, Inc.		RSP Permian, Inc. Pro Forma
	Six Months Ended June 30,		
	2015	2014	2014
	(In thousands)		
Revenues:			
Oil sales	$121,222	$117,606	$122,064
Natural gas sales	4,261	5,323	5,514
NGL sales	4,356	8,892	9,228
Total revenues	129,839	131,821	136,806
Operating expenses:			
Lease operating expenses	27,304	16,342	17,036
Production and ad valorem taxes	9,599	9,840	10,091
Depreciation, depletion and amortization	71,121	38,096	41,728
Asset retirement obligation accretion	168	66	76
Exploration	2,067	1,989	1,989
General and administrative expenses	13,236	22,254	6,295
Total operating expenses	123,495	88,587	77,215
Operating income	6,344	43,234	59,591
Other income (expense):			
Other income, net	161	8	8
Loss on derivative instruments	(631)	(20,111)	(20,111)
Interest expense	(18,683)	(2,272)	(2,273)
Total other income (expense)	(19,153)	(22,375)	(22,376)
Income (loss) before taxes	(12,809)	20,859	37,215
Income tax (expense) benefit	6,331	(140,162)	(13,398)
Net income (loss)	$(6,478)	$(119,303)	$23,817

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Three Months Ended June 30, 2015 Compared to the Three Months Ended June 30, 2014

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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,			
	2015	2014	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$73,917	$66,134	$7,783	12 %
Natural gas sales	2,028	3,117	(1,089)	(35)%
NGL sales	2,520	4,811	(2,291)	(48)%
Total revenues	$78,465	$74,062	$4,403	6 %
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$53.68	$96.26	$(42.58)	(44)%
Oil (per Bbl) (after impact of cash settled derivatives)	67.22	93.12	(25.90)	(28)%
Natural gas (per Mcf)	1.97	4.38	(2.41)	(55)%
Natural gas (per Mcf) (after impact of cash settled derivatives)	1.97	4.38	(2.41)	(55)%
NGLs (per Bbl)	9.69	28.47	(18.78)	(66)%
Total (per Boe) (excluding impact of cash settled derivatives)	$43.37	$75.96	$(32.59)	(43)%
Total (per Boe) (after impact of cash settled derivatives)	$53.68	$73.74	$(20.06)	(27)%
Production:				
Oil (MBbls)	1,377	687	690	100 %
Natural gas (MMcf)	1,029	712	317	45 %
NGLs (MBbls)	260	169	91	54 %
Total (MBoe)	1,809	975	834	86 %
Average daily production volume:				
Total (Boe/d)	19,879	10,714	9,165	86 %

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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,			
	2015		2014	
Average realized oil price ($/Bbl)	$53.68		$96.26	
Average NYMEX ($/Bbl)	57.94		103.03	
Differential to NYMEX	(4.26	)	(6.77	)
Average realized oil price to NYMEX percentage	93	%	93	%
Average realized natural gas price ($/Mcf)	$1.97		$4.38	
Average NYMEX ($/Mcf)	2.65		4.58	
Differential to NYMEX	(0.68	)	(0.20	)
Average realized natural gas price to NYMEX percentage	74	%	96	%
Average realized NGL price ($/Bbl)	$9.69		$28.47	
Average NYMEX oil price ($/Bbl)	57.94		103.03	
Average realized NGL price to NYMEX oil price percentage	17	%	28	%

Our average realized oil price as a percentage of the average NYMEX price was 93% for both the three months ended June 30, 2015 and 2014. All of our oil contracts are impacted by the Midland-Cushing differential, which was negative $0.60 per Bbl for the second quarter of 2015 as compared to negative $8.39 per Bbl in the comparable 2014 period.

Oil revenues increased 12% to $73.9 million for the three months ended June 30, 2015 from $66.1 million for the 2014 period as a result of an increase in oil production volumes of 690 MBbls, or 100%, partially offset by a $42.58 per Bbl decrease, or 44%, in our average realized price for oil.

Natural gas revenues decreased 35% and were $2.0 million and $3.1 million for the three months ended June 30, 2015 and 2014, respectively. Natural gas prices decreased by $2.41 per Mcf, or 55%, partially offset by an increase in production volumes of 317 MMcf, or 45%.

NGL revenues decreased 48% to $2.5 million for the three months ended June 30, 2015 from $4.8 million for the 2014 period as a result of an $18.78 per Bbl decrease, or 66%, in our average realized NGL price partially offset by an increase in NGL production volumes of 91 MBbls, or 54%. NGL prices were down a greater percentage than the NYMEX benchmark prices for oil and natural gas due to a more pronounced decrease in NGL prices over the past year as a result of an abundance of supply of NGLs.

Our higher production volumes for all products was primarily a result of increased production from our drilling program, along with the full period impact of our acquisitions closed in 2014.

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

	Three Months Ended June 30, 2015	2014	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$14,693	$9,279	$5,414	58 %
Production and ad valorem taxes	5,402	5,964	(562)	(9)%
Depreciation, depletion and amortization	39,620	21,734	17,886	82 %
Asset retirement obligation accretion	84	38	46	121 %
Exploration expense	889	1,233	(344)	(28)%
General and administrative expenses	6,865	5,238	1,627	31 %
Total operating expenses before loss (gain) on sale of assets	$67,553	$43,486	$24,067	55 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$7.63	$8.55	(0.92)	(11)%
Gathering and transportation	0.49	0.97	(0.48)	(49)%
Production and ad valorem taxes	2.99	6.12	(3.13)	(51)%
Depreciation, depletion and amortization	21.90	22.29	(0.39)	(2)%
Asset retirement obligation accretion	0.05	0.04	0.01	25 %
Exploration expense	0.49	1.26	(0.77)	(61)%
General and administrative - cash component	2.47	3.66	(1.19)	(33)%
General and administrative - (non IPO stock comp)(1)	1.14	0.67	0.47	70 %
General and administrative - (IPO stock comp)(2)	0.19	1.03	(0.84)	(82)%
Total operating expenses per Boe	$37.35	$44.59	$(7.24)	(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) IPO stock comp consists of two components. One component represents restricted stock awarded to certain employees as a result of a successful IPO. These one-time awards vest over time for retention purposes. The other component represents non-cash compensation expense associated with incentive units owned by certain members of management. These incentive units determined the stock allocation between management and Natural Gas Partners and had no dilutive impact or cash impact to the Company. See the discussion of incentive units in Note 9-Equity Based Compensation of Notes to Consolidated Financial Statements included in “Part I, Item 1. Notes to Consolidated Financial Statements.”

Lease Operating Expenses. Lease operating expenses increased 58% to $14.7 million for the three months ended June 30, 2015 from $9.3 million for the 2014 period. The increase in our lease operating expense was attributable to the increase in production in 2015. On a per Boe basis, lease operating expense, excluding gathering and transportation costs, decreased from $8.55 per Boe in 2014 to $7.63 per Boe in 2015. Gathering and transportation costs, which are included in lease operating expenses, were $0.9 million in both the three months ended June 30, 2015 and 2014. On a per Boe basis, our gathering and transportation costs were $0.49 and $0.97 for the three months ended June 30, 2015 and 2014, respectively.

Production and Ad Valorem Taxes. Production and ad valorem taxes decreased 9% to $5.4 million for the three months ended June 30, 2015 from $6.0 million for 2014 period and decreased 51% on a per Boe basis to $2.99 per Boe for the three months ended June 30, 2015 due to lower revenues per Boe and higher production volumes in the 2015 period.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization ("DD&A") expense increased 82% to $39.6 million for the three months ended June 30, 2015 from $21.7 million for 2014 period mainly due to increased production. The DD&A rate decreased 2% to $21.90 per Boe for the three months ended June 30, 2015 from $22.29 per Boe for the 2014 period. The decrease in depletion per Boe in 2015 was due to an increase in our reserves volume over the last year, both from our successful drilling program and through acquisitions, somewhat offset by additional capitalized costs in proved property incurred from these activities.

Exploration Expense. Exploration expense decreased from $1.2 million for the three months ended June 30, 2014 to $0.9 million for the 2015 period due to less expenditures on geological and geophysical activity in 2015.

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General and Administrative Expenses. General and administrative expenses increased to $6.9 million for the three months ended June 30, 2015, from $5.2 million for the 2014 period primarily due to increases in employee headcount and related expense. Share-based compensation expense, which was recorded in General and administrative expenses, was $2.4 million for the three months ended June 30, 2015 and $1.7 million for the 2014 period.

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

	Three Months Ended June 30, 2015	2014	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income, net	$(37)	$(302)	$265	88%
Gain (loss) on derivative instruments	(12,962)	(15,958)	2,996	19%
Interest expense	(9,367)	(1,142)	(8,225)	(720)%
Total other income (expense)	$(22,366)	$(17,402)	$(4,964)	(29)%

Other Income. Other income was minimal for both the three months ended June 30, 2015 and 2014.

Gain (Loss) on Derivative Instruments. During the three months ended June 30, 2015, we recorded a $13.0 million loss as compared to a $16.0 million loss in the 2014 period. The change was a result of realized gains on our derivative positions and the future commodity price outlook as of June 30, 2015 as compared to June 30, 2014, along with additional derivative contracts entered into during 2014 and 2015.

Interest Expense. During the three months ended June 30, 2015, we recorded $9.4 million of interest expense as compared to $1.1 million in the 2014 period. The change was primarily the result of expense incurred on our senior notes issued in September 2014.

Income Tax Expense. During the three months ended June 30, 2015, we recorded $6.0 million of income tax benefit compared to $4.9 million of income tax expense in the 2014 period. The decrease is a result of lower taxable income in the 2015 period.

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Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014

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

	Six Months Ended June 30, 2015	2014	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$121,222	$117,606	$3,616	3 %
Natural gas sales	4,261	5,323	(1,062)	(20)%
NGL sales	4,356	8,892	(4,536)	(51)%
Total revenues	$129,839	$131,821	$(1,982)	(2)%
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$49.38	$95.54	$(46.16)	(48)%
Oil (per Bbl) (after impact of cash settled derivatives)	68.98	93.29	(24.31)	(26)%
Natural gas (per Mcf)	2.14	4.14	(2.00)	(48)%
Natural gas (per Mcf) (after impact of cash settled derivatives)	2.14	4.14	(2.00)	(48)%
NGLs (per Bbl)	9.53	29.44	(19.91)	(68)%
Total (per Boe) (excluding impact of cash settled derivatives)	$40.02	$75.46	$(35.44)	(47)%
Total (per Boe) (after impact of cash settled derivatives)	$54.86	$73.87	$(19.01)	(26)%
Production:				
Oil (MBbls)	2,455	1,231	1,224	99 %
Natural gas (MMcf)	1,989	1,285	704	55 %
NGLs (MBbls)	457	302	155	51 %
Total (MBoe)	3,244	1,747	1,497	86 %
Average daily production volume:				
Total (Boe/d)	17,923	9,652	8,271	86 %

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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,			
	2015		2014	
Average realized oil price ($/Bbl)	$49.38		$95.54	
Average NYMEX ($/Bbl)	53.29		100.82	
Differential to NYMEX	(3.91	)	(5.28	)
Average realized oil price to NYMEX percentage	93	%	95	%
Average realized natural gas price ($/Mcf)	$2.14		$4.14	
Average NYMEX ($/Mcf)	2.82		4.65	
Differential to NYMEX	(0.68	)	(0.51	)
Average realized natural gas price to NYMEX percentage	76	%	89	%
Average realized NGL price ($/Bbl)	$9.53		$29.44	
Average NYMEX oil price ($/Bbl)	53.29		100.82	
Average realized NGL price to NYMEX oil price percentage	18	%	29	%

Our average realized oil price as a percentage of the average NYMEX price decreased to 93% for the six months ended June 30, 2015 as compared to 95% in the comparable 2014 period. All of our oil contracts are impacted by the Midland-Cushing differential, which was negative $1.29 per Bbl for the first six months of 2015 as compared to negative $5.95 per Bbl in the comparable 2014 period. In addition, the lower NYMEX price of oil in the current period makes the relative percentage fluctuate to a greater degree than at higher oil prices.

Oil revenues increased 3% to $121.2 million for the six months ended June 30, 2015 from $117.6 million for the 2014 period as a result of an increase in oil production volumes of 1,224 MBbls, or 99%, partially offset by a $46.16 per Bbl decrease, or 48%, in our average realized price for oil.

Natural gas revenues decreased 20% and were $4.3 million and $5.3 million for the six month periods ended June 30, 2015 and 2014, respectively. Our average realized natural gas price decreased by $2.00 per MMcf, or 48%, partially offset by an increase in production volumes of 704 MMcf, or 55%.

NGL revenues decreased 51% to $4.4 million for the six months ended June 30, 2015 from $8.9 million for the 2014 period as a result of a $19.91 per Bbl decrease, or 68%, in our average realized NGL price partially offset by an increase in NGL production volumes of 155 MBbls, or 51%. NGL prices were down a greater percentage than the

NYMEX benchmark prices for oil and natural gas due to a more pronounced decrease in NGL prices over the past year as a result of an abundance of supply of NGLs.

Our higher production volumes for all products was primarily a result of increased production from our drilling program, along with the full period impact of our acquisitions closed during 2014.

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

	Six Months Ended June 30, 2015	2014	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$27,304	$16,342	$10,962	67 %
Production and ad valorem taxes	9,599	9,840	(241)	(2)%
Depreciation, depletion and amortization	71,121	38,096	33,025	87 %
Asset retirement obligation accretion	168	66	102	155 %
Exploration expense	2,067	1,989	78	4 %
General and administrative expenses	13,236	22,254	(9,018)	(41)%
Total operating expenses before loss (gain) on sale of assets	$123,495	$88,587	$34,908	39 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$7.89	$8.59	(0.70)	(8)%
Gathering and transportation	0.53	0.76	(0.23)	(30)%
Production and ad valorem taxes	2.96	5.63	(2.67)	(47)%
Depreciation, depletion and amortization	21.92	21.81	0.11	1 %
Asset retirement obligation accretion	0.05	0.04	0.01	25 %
Exploration expense	0.64	1.14	(0.50)	(44)%
General and administrative - cash component	2.68	4.91	(2.23)	(45)%
General and administrative - (non IPO stock comp)(1)	1.15	0.54	0.61	113 %
General and administrative - (IPO stock comp)(2)	0.25	7.29	(7.04)	(97)%
Total operating expenses per Boe	$38.07	$50.71	$(12.64)	(25)%

(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) IPO stock comp consists of two components. One component represents restricted stock awarded to certain employees as a result of a successful IPO. These one-time awards vest over time for retention purposes. The other component represents non-cash compensation expense associated with incentive units owned by certain members of management. These incentive units determined the stock allocation between management and Natural Gas Partners and had no dilutive impact or cash impact to the Company. See the discussion of incentive units in Note 9-Equity Based Compensation of Notes to Consolidated Financial Statements included in “Part I, Item 1. Notes to Consolidated Financial Statements.”

Lease Operating Expenses. Lease operating expenses increased 67% to $27.3 million for the six months ended June 30, 2015 from $16.3 million for the 2014 period. The increase in our lease operating expense was attributable to the increase in production in 2015. On a per Boe basis, lease operating expense, excluding gathering and transportation costs, decreased from $8.59 per Boe in 2014 to $7.89 per Boe in 2015. Gathering and transportation costs, which are included in lease operating expenses, were $1.7 million and $1.3 million for the six months ended June 30, 2015 and 2014, respectively. On a per Boe basis, our gathering and transportation costs were $0.53 and $0.76 for the six months ended June 30, 2015 and 2014, respectively.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 2% to $9.6 million for the six months ended June 30, 2015 from $9.8 million for the 2014 period. On a Boe basis, these costs declined 47% to $2.96 per Boe for the six months ended June 30, 2015 due to lower revenues per Boe and higher production volumes in the 2015 period.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (“DD&A”) expense increased 87% to $71.1 million for the six months ended June 30, 2015 from $38.1 million for 2014 period mainly due to increased production. The DD&A rate increased 1% to $21.92 per Boe for the six months ended June 30, 2015 from $21.81 per Boe for the 2014 period. The increase in depletion per Boe in 2015 was due to additional capitalized costs in proved property incurred from both our successful drilling program and through acquisitions, being more than offset by an increase in our reserves volumes over last year from these these activities.

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Exploration Expense. Exploration expense was $2.1 million and $2.0 million for the six months ended June 30, 2015 and 2014, respectively.

General and Administrative Expenses. General and administrative expenses decreased to $13.2 million for the six months ended June 30, 2015, from $22.3 million for the 2014 period primarily due to decreases in non-cash incentive unit compensation and equity-based compensation. Share-based compensation expense, which was recorded in General and administrative expenses, was $4.5 million for the six months ended June 30, 2015 and $13.7 million for the 2014 period. Included in share-based compensation for the 2014 period was compensation expense related to incentive units ($11.4 million) that were owned by certain members of management. These incentive units provided a mechanism for the allocation of stock between members of management and the Company's private equity sponsor based upon return thresholds achieved. The stock issued to certain members of management and the expense recognized in the consolidated statement of operations as a result of these incentive units had no dilution effect to public shareholders, and was a non-cash expense.

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

	Six Months Ended June 30,			
	2015	2014	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income, net	$161	$8	$153	(1,913)%
Gain (loss) on derivative instruments	(631)	(20,111)	19,480	97%
Interest expense	(18,683)	(2,272)	(16,411)	(722)%
Total other income (expense)	$(19,153)	$(22,375)	$3,222	14%

Other Income. Other income was minimal for both the six months ended June 30, 2015 and 2014.

Gain (Loss) on Derivative Instruments. During the six months ended June 30, 2015, we recorded a $0.6 million loss as compared to a $20.1 million loss in the 2014 period. The change was a result of realized gains on our derivative positions and the future commodity price outlook as of June 30, 2015 as compared to June 30, 2014, along with additional derivative contracts entered into during the second half of 2014 and 2015.

Interest Expense. During the six months ended June 30, 2015, we recorded $18.7 million of interest expense as compared to $2.3 million in the 2014 period. The change was primarily the result of expense incurred on our senior notes issued in September 2014.

Income Tax Expense. During the six months ended June 30, 2015, we recorded $6.3 million of income tax benefit compared to $140.2 million of income tax expense in the 2014 period. The decrease is a result of a $132 million provision for deferred income taxes, in the first quarter of 2014 related to our change in tax status.

Capital Requirements and Sources of Liquidity

The Company’s primary sources of liquidity have been proceeds from equity and debt 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.

In 2014, we used a portion of the net proceeds from the IPO to fully repay our term loan and outstanding borrowings under our revolving credit facility. Later in August and September 2014, we used the proceeds from our stock offering and notes offering to repay all borrowings under our revolving credit facility. At June 30, 2015, we had no borrowings outstanding under our revolving credit facility and our borrowing base was $500 million.

During the second quarter of 2015, our capital expenditures totaled $147.0 million, which included approximately $134.9 million on drilling and completion activities and $12.1 million of infrastructure and other. Approximately 15% of total capital expenditures were on non-operated properties. In 2014, we spent approximately $442 million on drilling and completion activities, $42 million of infrastructure and other, and approximately $362 million of acquisitions and additions to leasehold.

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Subsequent to the end of the second quarter of 2015, the Company has closed or entered into definitive purchase agreements to acquire undeveloped acreage and oil and gas producing properties located in Martin and Glasscock counties for an aggregate purchase price of approximately $274 million, subject to certain purchase price adjustments. The aggregate acquisitions include 5,704 net acres, with an average royalty burden of 23%, in our core focus areas with current production of approximately 1,569 Boe/d and 162 net horizontal drilling locations. Approximately $65 million of the acquisitions have been funded through cash on hand and $50 million drawn on the Company's revolving credit facility; and the Company intends to finance the remaining acquisitions, subject to market conditions and other factors, with proceeds from one or more capital market transactions, which may include debt or equity offerings. In the absence of capital markets transactions, the Company intends to fund the acquisitions with remaining availability under its revolving credit facility. However, the remaining transactions remain subject to the completion of due diligence and satisfaction of other closing conditions. There can be no assurances that the Company will close on all or any portion of the remaining acquisitions.

Because we operate a high percentage of our acreage, the amount and timing of these capital expenditures are largely discretionary. We could choose to defer a portion of planned 2015 capital expenditures depending on a variety of factors, including: 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 upon current expectations, we believe we have sufficient liquidity through our cash flow from operations and additional 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 significant additional capital expenditures will 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 assure you 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 $23.0 million and $43.7 million at June 30, 2015 and December 31, 2014, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $44.1 million and $56.3 million at June 30, 2015 and December 31, 2014, 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, 2014.

Cash Flows

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

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	Six Months Ended June 30,	
	2015	2014
	(In thousands)	
Net cash provided by operating activities	$91,619	$97,093
Net cash used in investing activities	(249,119)	(270,626)
Net cash provided by financing activities	145,263	175,032

Net cash provided by operating activities was approximately $91.6 million and $97.1 million for the six months ended June 30, 2015 and 2014, respectively. The decrease in net cash provided by operating activities for the six months ended June 30, 2015, as compared to the 2014 period, was mainly due to amounts received from our settled derivative contracts. These amounts totaled $48.3 million in the 2015 period and were payments of $1.8 million in the 2014 period.

Net cash used in investing activities was approximately $249.1 million and $270.6 million for the six months ended June 30, 2015 and 2014, respectively. The increase in the 2015 period, compared to the 2014 period, was due to additional drilling and completion activity in the 2015 period.

Net cash provided by financing activities was approximately $145.3 million and $175.0 million for the six months ended June 30, 2015 and 2014, respectively. The 2015 period included $147.0 million of capital contributions received in a follow-on stock offering, while the 2014 period included $163.1 million of capital contributions received in the IPO in both instances a portion of the proceeds was used to pay down existing debt balances.

Our Revolving Credit Facility

Our credit agreement has a borrowing base of $500 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 borrowing base was confirmed at $500.0 million in May 2015 and the next borrowing base redetermination is scheduled for November 2015. As of June 30, 2015, we had no borrowings and $0.6 million of letters of credit outstanding under our revolving credit facility and $499.4 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 our consolidated current assets (includes unused commitments under our revolving credit facility and excludes restricted cash and derivative assets) to our consolidated current liabilities

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(excluding the current portion of long term debt under the credit facility and derivative liabilities), of not less than 1.0 to 1.0 at the end of each fiscal quarter thereafter;

- a senior secured leverage ratio, which is the ratio of the sum of all of our secured debt to our consolidated EBITDAX (as defined in our revolving credit facility) for the four fiscal quarters then ended, of not less than 3.5 to 1.0 commencing at the issuance of any Permitted Unsecured Notes (as defined in our revolving credit facility, but in any event including the notes offered hereby) and as of the last day of each fiscal quarter thereafter; and
- a leverage ratio, which is the ratio of the sum of all our debt to our 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.

We were in compliance with such covenants and ratios as of June 30, 2015.

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. We have 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 125 to 200 basis points, depending on the percentage of our borrowing base utilized. Adjusted base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank’s reference 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 25 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. We 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, 2015, our 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.

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 that 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, 2015 were as follows:

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Description & Production Period	Volume (Bbls)	Weighted Average Floor price ($/Bbl)(1)	Weighted Average Ceiling price ($/Bbl)(1)	Weighted Average Short Put price ($/Bbl)(1)	Weighted Average Swap price ($/Bbl)(1)
Crude Oil Swaps:					
July 2015 — December 2015	60,000				$92.60
Crude Oil Collars:					
July 2015 — December 2015	816,000	$85.70	$94.71		
July 2015 — September 2015	90,000	$85.00	$92.60		
October 2015 — December 2015	90,000	$85.00	$92.33		
January 2016 — March 2016	75,000	$55.00	$72.00	$45.00	
January 2016 — December 2016	480,000	$55.00	$74.41	$45.00	

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

The fair value of our derivative contracts as of June 30, 2015 was a net asset of $26.9 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, 2015, 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 March 31, 2015. 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, 2015 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

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As described above, 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, 2015 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, 2014, 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, 2015:

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 Amount of Shares that May Yet Be Purchased under Plans or Programs
April 2015	74	$28.57	—	$—
May 2015	844	$28.78	—	$—
June 2015	766	$28.68	—	$—
Total	1,684	$28.73	—	$—

'(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 42 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 3, 2015
By:	/s/ Barry S. Turcotte
	Barry S. Turcotte
	Chief Accounting Officer
	(Principal Accounting Officer)
Date:	August 3, 2015

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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).
10.1	Amended and Restated Credit Agreement, dated September 10, 2013, by and between RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-1 (File No. 377-00338) filed with the Commission on October 8, 2013).
10.2	First Amendment to Amended and Restated Credit Agreement, dated June 9, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on June 9, 2014).
10.3	Second Amendment to Amended and Restated Credit Agreement, dated August 29, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on September 4, 2014).
10.4	Third Amendment to Amended and Restated Credit Agreement, dated September 12, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on September 18, 2014).
10.5(c)	2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 22, 2014).
10.6(c)	Form of Restricted Stock Grant and Award Agreement (Performance Vesting) (incorporated by reference to the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on April 16, 2014).
10.7(c)	Form of Restricted Stock Grant and Award Agreement (incorporated by reference to Exhibit 10.3 of the Company’s Quarterly Report on Form 10-Q (File No. 001-36264) filed with the Commission on May 15, 2014).
10.8(c)	

	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.4 to the Company’s Registration Statement on Form S-1/A (File No. 333-192268) filed with the Commission on January 2, 2014).
10.9(c)	Executive Change in Control and Severance Benefit Plan of RSP Permian, Inc. (incorporated by reference to Exhibit 5.1 to the Company's Registration Statement on Form S-1/A (File No. 333-196388) filed with the Commission on January 25, 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.

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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.
(a) Management contract or compensatory plan.