Parsley Energy, Inc.
Form 10-Q
August 05, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2016

or

¨ 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: 001-36463

PARSLEY ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	46-4314192
(State or other jurisdiction	(I.R.S. Employer
of incorporation or organization)	Identification No.)
	78701
303 Colorado Street, Suite 3000	

Austin, Texas
(Address of principal executive offices) (Zip Code)

(737) 704-2300

(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 x No ¨

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

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

As of August 5, 2016, the registrant had 171,230,047 shares of Class A common stock and 28,008,573 shares of Class B common stock outstanding.

PARSLEY ENERGY, INC.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (the "Quarterly Report") includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Quarterly Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressi intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under, but not limited to, the heading "Item 1A. Risk Factors" and elsewhere in our Annual Report on Form 10-K for the year ended December 31, 2015 (the "Annual Report"), and our other filings with the United States Securities and Exchange Commission ("SEC"). These forward-looking statements are based on management's current beliefs, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- exploration and development drilling prospects, inventories, projects and programs;
- ability to replace the reserves we produce through drilling and property acquisitions;
- financial strategy, liquidity and capital required for our development program;
- realized oil, natural gas and natural gas liquids (NGLs) prices;
- timing and amount of future production of oil, natural gas and NGLs;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- ability to obtain permits and governmental approvals;
- pending legal or environmental matters;
- marketing of oil, natural gas and NGLs;
- leasehold or business acquisitions;
- costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical.

All forward-looking statements speak only as of the date of this Quarterly Report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

The terms defined in this section are used throughout this Quarterly Report:

(1) Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used in reference to crude oil, condensate or natural gas liquids.
(2) Boe. One barrel of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.
(3) Boe/d. One barrel of oil equivalent per day.
(4) British thermal unit or Btu. The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.
(5) 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.
(6) Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
(7) Dry hole. 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.
(8) Exploitation. A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.
(9) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
   (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are referred to as geological and geophysical or G&G costs.
   (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title deference, and the maintenance of land and lease records.
   (iii) Dry hole contributions and bottom hole contributions.
   (iv) Costs of drilling and equipping exploratory wells.
   (v) Costs of drilling exploratory-type stratigraphic test wells.
   (vi) Idle drilling rig fees which are not chargeable to joint operations.
(10) Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.
(11) Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC’s Regulation S-X, Rule 4-10(a)(15).
(12) Formation. A layer of rock which has distinct characteristics that differ from nearby rock.
(13) GAAP. Accounting principles generally accepted in the United States.
(14) Gross acres or gross wells. The total acres or wells, as the case may be, in which an entity owns a working interest.
(15) Horizontal drilling. A drilling technique where a well is drilled vertically to a certain depth and then drilled laterally within a specified target zone.
(16) Lease operating expense. All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, allocated overhead charges, workover, insurance

and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

(17) LIBOR. London Interbank Offered Rate.

(18) MBbl. One thousand barrels of crude oil, condensate or NGLs.

(19) MBoe. One thousand barrels of oil equivalent.

(20) Mcf. One thousand cubic feet of natural gas.

(21) MMBtu. One million British thermal units.
(22) MMcf. One million cubic feet of natural gas.
(23) Natural gas liquids or NGLs. The combination of ethane, propane, butane, isobutane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
(24) Net acres or net wells. The percentage of total acres or wells, as the case may be, an owner has out of a particular number of gross acres or wells. For example, an owner who has 50% interest in 100 gross acres owns 50 net acres.
(25) NYMEX. The New York Mercantile Exchange.
(26) Operator. The entity responsible for the exploration, development and production of a well or lease.
(27) PE Units. The single class of units in which all of the membership interests (including outstanding incentive units) in Parsley Energy, LLC were converted to in connection with our initial public offering.
(28) Proved developed reserves. Proved reserves that can be expected to be recovered:
(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; or
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
(29) Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence, the project within a reasonable time. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).
(30) Proved undeveloped reserves or PUDs. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

(31) Reasonable certainty. A high degree of confidence. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).
(32) Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
(33) Reliable technology. A grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.
(34) Reserves. 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 prospects 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.

(35) Reservoir. A porous and permeable underground formation containing a natural accumulation of producible hydrocarbons that is confined by impermeable rock or water barriers and is separate from other reservoirs.

(36) SEC. The United States Securities and Exchange Commission.

(37) Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

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

(39) Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.
(40) 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.
(41) Workover. Operations on a producing well to restore or increase production.
(42) WTI. West Texas Intermediate crude oil, which is a light, sweet crude oil, characterized by an American Petroleum Institute gravity, or API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a benchmark for other crude oils.

PART 1: FINANCIAL INFORMATION

Item 1: Financial Statements

PARSLEY ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2016	December 31, 2015
	(In thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$441,024	$343,084
Restricted cash	2,158	1,139
Accounts receivable:		
Joint interest owners and other	40,855	14,998
Oil, natural gas and NGLs	47,764	21,219
Related parties	735	390
Short-term derivative instruments, net	27,662	83,262
Other current assets	30,601	24,234
Total current assets	590,799	488,326
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	3,027,514	2,246,161
Accumulated depreciation, depletion and impairment	(386,353)	(290,186)
Total oil and natural gas properties, net	2,641,161	1,955,975
Other property, plant and equipment, net	33,953	29,778
Total property, plant and equipment, net	2,675,114	1,985,753
NONCURRENT ASSETS		
Long-term derivative instruments, net	20,171	25,839
Other noncurrent assets	4,110	5,182
Total noncurrent assets	24,281	31,021
TOTAL ASSETS	$3,290,194	$2,505,100
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$157,334	$151,221
Revenue and severance taxes payable	45,596	37,109
Current portion of long-term debt	1,168	951
Short-term derivative instruments, net	18,672	34,518
Current portion of asset retirement obligations	3,036	4,698
Total current liabilities	225,806	228,497
NONCURRENT LIABILITIES		
Long-term debt	742,471	546,832
Asset retirement obligations	13,772	13,522

Deferred tax liability	51,057	62,962
Payable pursuant to tax receivable agreement	51,504	51,504
Long-term derivative instruments, net	15,377	15,142
Other noncurrent liabilities	2	—
Total noncurrent liabilities	874,183	689,962
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock, $0.01 par value, 50,000,000 shares authorized, none issued and outstanding	—	—
Common stock		
Class A, $0.01 par value, 600,000,000 shares authorized, 167,215,201 shares issued and 167,091,043 shares outstanding at June 30, 2016 and 136,728,906 shares issued and 136,623,407 shares outstanding at December 31, 2015	1,665	1,360
Class B, $0.01 par value, 125,000,000 shares authorized, 32,145,296 issued and outstanding at June 30, 2016 and December 31, 2015	321	321
Additional paid in capital	1,851,975	1,252,020
(Accumulated deficit) retained earnings	(29,804)	10,868
Treasury stock, at cost, 124,158 shares and 105,421 at June 30, 2016 and December 31, 2015	(290)	(77)
Total stockholders' equity	1,823,867	1,264,492
Noncontrolling interest	366,338	322,149
Total equity	2,190,205	1,586,641
TOTAL LIABILITIES AND EQUITY	$3,290,194	$2,505,100

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

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PARSLEY ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands, except per share data)			
REVENUES				
Oil sales	$91,129	$63,418	$143,160	$107,106
Natural gas sales	5,834	6,696	11,377	13,652
Natural gas liquids sales	9,347	7,746	14,041	12,313
Total revenues	106,310	77,860	168,578	133,071
OPERATING EXPENSES				
Lease operating expenses	14,204	18,464	28,102	34,862
Production and ad valorem taxes	6,407	5,431	10,602	9,926
Depreciation, depletion and amortization	55,988	44,407	105,372	81,788
General and administrative expenses (including stock-based compensation of $3,391 and $2,112 for the three months ended June 30, 2016 and 2015 and $6,150 and $3,753 for the six months ended June 30, 2016 and 2015)	17,307	14,083	36,606	27,064
Exploration costs	8,978	1,515	9,666	4,734
Acquisition costs	486	—	486	—
Accretion of asset retirement obligations	215	221	385	470
Rig termination costs	—	3,870	—	8,970
Other operating expenses	1,651	23	2,547	23
Total operating expenses	105,236	88,014	193,766	167,837
OPERATING INCOME (LOSS)	1,074	(10,154)	(25,188)	(34,766)
OTHER INCOME (EXPENSE)				
Interest expense, net	(12,199)	(11,099)	(23,393)	(22,940)
(Loss) gain on sale of property	(469)	1,031	(119)	1,031
Derivative loss	(27,304)	(17,733)	(25,216)	(10,591)
Other income, net	492	1,559	251	1,838
Total other expense, net	(39,480)	(26,242)	(48,477)	(30,662)
LOSS BEFORE INCOME TAXES	(38,406)	(36,396)	(73,665)	(65,428)
INCOME TAX BENEFIT	10,918	10,216	20,486	15,690
NET LOSS	(27,488)	(26,180)	(53,179)	(49,738)
LESS: NET LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	6,111	7,051	12,448	13,585
NET LOSS ATTRIBUTABLE TO PARSLEY ENERGY,	$(21,377)	$(19,129)	$(40,731)	$(36,153)

INC. STOCKHOLDERS				
Net loss per common share:				
Basic	$(0.13)	$(0.18)	$(0.28)	$(0.35)
Diluted	$(0.13)	$(0.18)	$(0.28)	$(0.35)
Weighted average common shares outstanding:				
Basic	158,662	108,058	147,313	104,684
Diluted	158,662	108,058	147,313	104,684

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

	Issued Shares						Shares				
	Class A Common Stock	Class B Common Stock	Class A Common Stock	Class B Common Stock	Additional paid in capital	(Accumulated deficit) retained earnings	Treasury stock	Treasury stock	Total stockholders' equity	Noncontrolling interest	Total equity
(In thousands)											
Balance at December 31, 2015	136,729	32,145	$1,360	$321	$1,252,020	$10,868	105	$(77)	$1,264,492	$322,149	$1,586,641
Adoption of ASU 2016-09	—	—	—	—	—	59	—	—	59	—	59
Restated balance	136,729	32,145	1,360	321	1,252,020	10,927	105	(77)	1,264,551	322,149	1,586,700
Issuance costs, net of underwriters discount and expenses	30,475	—	305	—	659,082	—	—	—	659,387	—	659,387
Change in equity due to issuance of PE Units by Parsley LLC	—	—	—	—	(56,637)	—	—	—	(56,637)	56,637	—
Increase in net deferred tax liability due to issuance of PE Units by Parsley	—	—	—	—	(8,640)	—	—	—	(8,640)	—	(8,640)

LLC											
Vesting of restricted stock units	11	—	—	—	—	—	—	—	—	—	—
Repurchase of common stock	—	—	—	—	—	—	11	(213)	(213)	—	(213)
Restricted stock forfeited	—	—	—	—	(18)	—	8	—	(18)	—	(18)
Stock-based compensation	—	—	—	—	6,168	—	—	—	6,168	—	6,168
Net loss	—	—	—	—	—	(40,731)	—	—	(40,731)	(12,448)	(53,179)
Balance at June 30, 2016	167,215	32,145	$1,665	$321	$1,851,975	$(29,804)	124	$(290)	$1,823,867	$366,338	$2,190,205

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2016	2015
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(53,179)	$(49,738)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	105,372	81,788
Exploration costs	5,677	1,755
Accretion of asset retirement obligations	385	470
Loss (gain) on sale of property	119	(1,031)
Amortization and write off of deferred loan origination costs	1,385	1,566
Amortization of bond premium	(383)	(382)
Stock-based compensation	6,150	3,753
Deferred income tax benefit	(20,486)	(15,690)
Derivative loss	25,216	10,591
Net cash received for derivative settlements	25,133	21,267
Net cash received for option premiums	7,013	17,398
Net premiums received on options that settled during the period	20,966	2,045
Changes in operating assets and liabilities, net of acquisitions:		
Restricted cash	(1,019)	—
Accounts receivable	(52,521)	19,151
Accounts receivable—related parties	(345)	2,966
Materials and supplies	—	3,767
Other current assets	(39,037)	(4,274)
Other noncurrent assets	482	(625)
Accounts payable and accrued expenses	12,388	(15,144)
Revenue and severance taxes payable	8,487	(632)
Other noncurrent liabilities	2	(374)
Net cash provided by operating activities	51,805	78,627
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development of oil and natural gas properties	(252,764)	(207,914)
Acquisitions of oil and natural gas properties	(548,724)	(29,754)
Acquisition of Pacesetter	—	(2,408)
Additions to other property and equipment	(6,487)	(16,127)
Proceeds from sale of oil and natural gas properties	—	1,190
Other investing activities	—	(925)
Net cash used in investing activities	(807,975)	(255,938)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under long-term debt	200,000	45,000
Payments on long-term debt	(503)	(120,326)

Debt issuance costs	(4,561)	(746)
Proceeds from issuance of common stock, net	659,387	224,002
Repurchase of common stock	(213)	(71)
Net cash provided by financing activities	854,110	147,859
Net increase (decrease) in cash and cash equivalents	97,940	(29,452)
Cash and cash equivalents at beginning of period	343,084	50,550
Cash and cash equivalents at end of period	$441,024	$21,098
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for interest	$21,241	$22,010
Cash paid for income taxes	$315	$—
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:		
Asset retirement obligations incurred, including changes in estimate	$(1,257)	$2,247
Reductions to oil and natural gas properties - change in capital accruals	$(6,281)	$(11,240)
Additions to other property and equipment funded by capital lease borrowings	$505	$170

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1. ORGANIZATION AND NATURE OF OPERATIONS

Parsley Energy, Inc. (either individually or together with its subsidiaries, as the context requires, the “Company”) was formed on December 11, 2013, pursuant to the laws of the State of Delaware, and is engaged in the acquisition and development of unconventional oil and natural gas reserves located in the Permian Basin, which is located in West Texas and Southeastern New Mexico.

On May 13, 2016, the Company established a limited liability company, Parsley Minerals, LLC (“Minerals LLC”), as a wholly owned subsidiary of Parsley Energy, L.P. (“Parsley LP”). As discussed in Note 14—Subsequent Events, on July 14, 2016 Minerals LLC acquired, from unaffiliated third-party sellers, certain mineral interests, surface rights and net production located in Pecos and Reeves Counties, Texas.

Public Offerings of Common Stock

On April 4, 2016, the Company entered into an agreement to sell 20,987,500 shares of Class A Common Stock, par value $0.01 per share (“Class A Common Stock”), (including 2,737,500 shares issued pursuant to the underwriters’ option to purchase additional shares) at a price of $21.40 per share in an underwritten public offering (the “April Offering”). The April Offering closed on April 8, 2016 and resulted in gross proceeds of approximately $449.1 million to the Company and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately $433.2 million.

On May 23, 2016, the Company entered into an agreement to sell 9,487,500 shares of Class A Common Stock (including 1,237,500 shares issued pursuant to the underwriters’ option to purchase additional shares) at a price of $24.60 per share in an underwritten public offering (the “May Offering”). The May Offering closed on May 27, 2016 and resulted in gross proceeds of approximately $233.4 million to the Company and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately $226.2 million.

Private Placement of Senior Notes

On May 24, 2016, Parsley Energy, LLC, the Company’s majority-owned subsidiary (“Parsley LLC”), and Parsley Finance Corp., Parsley LLC’s wholly owned subsidiary (“Finance Corp.”), as issuers, and certain subsidiaries of Parsley LLC, as guarantors, entered into an agreement to sell $200.0 million in aggregate principal amount of 6.250% senior notes due 2024 (the “2024 Notes”) in an offering that was exempt from registration under the Securities Act (the “Notes Offering”). The Notes Offering closed on May 27, 2016 and resulted in gross proceeds of $200.0 million to the Company and net proceeds, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $195.4 million.

NOTE 2. BASIS OF PRESENTATION

These condensed consolidated financial statements include the accounts of Parsley Energy, Inc. and its majority-owned subsidiary, Parsley LLC, and its wholly owned subsidiaries: (i) Parsley LP, (ii) Parsley Energy Management, LLC (the “General Partner”), (iii) Parsley Energy Operations, LLC (“Operations”) and its wholly owned subsidiary, Parsley Energy Aviation, LLC, (iv) Finance Corp and (v) Minerals LLC. These condensed consolidated financial statements also include the accounts of Pacesetter Drilling, LLC, a majority-owned subsidiary of Operations. Parsley LP owns a 42.5% noncontrolling interest in Spraberry Production Services, LLC (“SPS”). The Company accounts for its investment in SPS using the equity method of accounting. All significant intercompany and intra-company balances and transactions have been eliminated.

Certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted. We believe the disclosures made are adequate to make the information not misleading. We recommend that these condensed consolidated financial statements should be read in conjunction with the Company’s audited consolidated financial statements and related notes thereto included in the Annual Report.

In the opinion of management, the interim data includes all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the results for the interim period. The results of operations for the three and six months ended June 30, 2016, are not necessarily indicative of the operating results of the entire fiscal year ending December 31, 2016.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Use of Estimates

These condensed consolidated financial statements and related notes are presented in accordance with GAAP. Preparation in accordance with GAAP requires us to (1) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board ("FASB") and by the SEC and (2) make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Our management believes the major estimates and assumptions impacting our condensed consolidated financial statements are the following:

- estimates of proved reserves of oil and natural gas, which affect the calculations of depletion, depreciation and amortization ("DD&A") and impairment of capitalized costs of oil and natural gas properties;
- estimates of asset retirement obligations;
- estimates of the fair value of oil and natural gas properties we own, particularly properties that we have not yet explored, or fully explored, by drilling and completing wells;
- impairment of undeveloped properties and other assets;
- depreciation of property and equipment; and
- valuation of commodity derivative instruments.

Actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

Significant Accounting Policies

For a complete description of the Company's significant accounting policies, see Note 2—Summary of Significant Accounting Policies in the Annual Report.

Change in Accounting Principle

The Company adopted Accounting Standards Update ("ASU") 2015-03, Interest—Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, effective January 1, 2016. This standard requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. To the extent that there are no borrowings under the amended and restated credit agreement with Wells Fargo Bank, National Association, as administrative agent (as amended, the "Revolving Credit Agreement"), the related deferred loan costs will continue to be classified as an asset. The guidance required retrospective application in the condensed consolidated financial statements. The Company had no borrowings outstanding under the Revolving Credit Agreement at June 30, 2016 and December 31, 2015, and as such, approximately $1.7 million and $2.3 million, respectively, of deferred loan costs related to the Revolving Credit Agreement are included in "Other noncurrent assets" on the condensed consolidated balance sheets and as an operating activity on the condensed consolidated statement of cash flows included in this Quarterly Report. The Company's 7.500% senior notes due 2022 (the "2022 Notes") and 2024 Notes (collectively, the "Notes") are presented net of approximately $12.9 million and $9.1 million of deferred loan costs at June 30, 2016 and December 31, 2015, respectively.

The Company adopted ASU 2016-09, Compensation—Stock Compensation (Topic 718)—Improvements to Employee Share-Based Payment Accounting, effective January 1, 2016. This ASU is intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, including interim periods within those annual periods, and early application is permitted as of the beginning of an interim or annual reporting period. The ASU did not have a material effect on the Company’s financial statements and related disclosures.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current presentation.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Recent Accounting Pronouncements

In 2014 and 2016, the FASB issued ASU Nos. 2014-09, 2016-08, 2016-10, 2016-11 and 2016-12, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers amongst other things. The ASUs will replace most existing revenue recognition guidance in GAAP when it becomes effective. The new standard will be effective for the Company on January 1, 2018. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU Nos. 2014-09, 2016-08, 2016-10, 2016-11 and 2016-12 will have on its condensed consolidated financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

In May 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330): Simplifying the Measurement of Inventory, which requires entities that value inventory using the first-in, first-out or average cost method to measure inventory at the lower of cost and net realizable value. The amended guidance will be effective for the Company for fiscal years beginning after December 15, 2016, and for interim periods within those years. The amended guidance must be applied on a prospective basis and is not expected to materially affect the Company’s condensed consolidated financial statements or notes to the condensed consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which modifies the recognition of lease assets and lease liabilities for lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. The amended guidance will be effective for the Company for annual periods beginning after December 15, 2018. Early adoption is permitted. The Company is evaluating the effect that ASU 2016-02 will have on its condensed consolidated financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

In March 2016, the FASB issued ASU No. 2016-07, Investments—Equity Method and Joint Ventures (Topic 323) as part of the simplification initiative, which eliminates the requirement that when an investment qualifies for use of the equity method as a result of an increase in the level of ownership interest or degree of influence, an investor must adjust the investment, results of operations, and retained earnings retroactively on a step-by-step basis as if the equity method had been in effect during all previous periods that the investment had been held. The amended guidance will be effective for the Company for annual periods beginning after December 15, 2016. The amendments should be applied prospectively upon their effective date to increases in the level of ownership interest or degree of influence that result in the adoption of the equity method. Early adoption is permitted for any entity in any interim or annual period. The amended guidance is not expected to materially affect the Company’s condensed consolidated financial statements or notes to the condensed consolidated financial statements.

NOTE 3. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Instruments and Concentration of Risk

Objective and Strategy

The Company utilizes basis swap contracts, three-way collars and put spread options to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Oil Production Derivative Activities

All material physical sales contracts governing the Company's oil production are tied directly to, or are highly correlated with, NYMEX WTI oil prices. The Company uses put spread options to manage oil price volatility and basis swap contracts to reduce basis risk between NYMEX prices and the actual index prices at which the oil is sold.

The following table sets forth the volumes associated with the Company's outstanding oil derivative contracts expiring during the periods indicated and the weighted average oil prices for those contracts:

Crude Options	Six Months Ending December 31, 2016	Year Ending December 31, 2017
Purchased:		
Puts [1]		
Notional (MBbl)	4,165	5,898
Weighted average strike price	$ 45.10	$ 48.92
Sold:		
Puts [1]		
Notional (MBbl)	(4,165)	(5,898)
Weighted average strike price	$ 32.82	$ 37.07
Basis swap contracts: [2]		
Midland-Cushing index swap volume (MBbl)	1,516	4,290
Price differential ($/Bbl)	$ (0.87)	$ (1.03)

(1) The Company excluded from the tables above 12,399 notional MBbls with a fair value of $119.2 million related to amounts recognized under master netting agreements with derivative counterparties.

(2) Represents swaps that fix the basis differentials between the index prices at which the Company sells its oil produced in the Permian Basin and the Cushing WTI price.

Natural Gas Production Derivative Activities

All material physical sales contracts governing the Company's natural gas production are tied directly or indirectly to NYMEX Henry Hub natural gas prices or regional index prices where the natural gas is sold. The Company uses three-way collars to manage natural gas price volatility.

The following table sets forth the volumes associated with the Company's outstanding natural gas derivative contracts expiring during the periods indicated and the weighted average natural gas prices for those contracts:

Natural Gas Three-Way Collars	Year Ending December 31, 2017
Purchased:	
Puts	
Notional (MMbtu)	4,500
Weighted average strike price	$ 2.75
Sold:	
Puts	
Notional (MMbtu)	(4,500)
Weighted average strike price	$ 2.39
Calls	
Notional (MMbtu)	(4,500)
Weighted Average Strike Price	$ 4.01

PARSLEY ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Effect of Derivative Instruments on the Condensed Consolidated Financial Statements

All of the Company’s derivatives are accounted for as non-hedge derivatives and therefore all changes in the fair values of its derivative contracts are recognized as gains or losses in the earnings of the periods in which they occur. The Company recognized losses from its derivative activities of $27.3 million and $17.7 million for the three months ended June 30, 2016 and 2015, respectively. The Company recognized losses from its derivative activities of $25.2 million and $10.6 million for the six months ended June 30, 2016 and 2015, respectively. The losses are included in the condensed consolidated statements of operations line item, “Derivative loss.” The fair value of the derivative instruments is discussed in Note 13—Disclosures about Fair Value of Financial Instruments.

The Company classifies the fair value amounts of derivative assets and liabilities as gross current or noncurrent derivative assets or gross current or noncurrent derivative liabilities, whichever the case may be, excluding those amounts netted under master netting agreements. The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and liabilities at settlement or in the event of default under the agreements. Additionally, the Company maintains accounts with its brokers to facilitate financial derivative transactions in support of its risk management activities. Based on the value of the Company’s positions in these accounts and the associated margin requirements, the Company may be required to deposit cash into these broker accounts. During the three and six months ended June 30, 2016 and 2015, the Company did not receive or post any margins in connection with collateralizing its derivative positions.

The following table presents the Company’s net exposure from its offsetting derivative asset and liability positions, as well as cash collateral on deposit with the brokers as of the reporting dates indicated (in thousands):

	Gross Amount	Netting Adjustments	Net Exposure
June 30, 2016			
Derivative assets with right of offset or master netting agreements	$166,988	$(119,155)	$47,833
Derivative liabilities with right of offset or master netting agreements	(153,204)	119,155	(34,049)
December 31, 2015			
Derivative assets with right of offset or master netting agreements	$407,052	$(297,951)	$109,101
Derivative liabilities with right of offset or master netting agreements	(347,611)	297,951	(49,660)

Concentration of Credit Risk

The financial integrity of the Company’s exchange-traded contracts is assured by NYMEX through systems of financial safeguards and transaction guarantees, and is therefore subject to nominal credit risk. Over-the-counter traded options expose the Company to counterparty credit risk. These over-the-counter options are entered into with a large multinational financial institution with investment grade credit rating or through brokers that require all the transaction parties to collateralize their open option positions. The gross and net credit exposure from our commodity derivative contracts as of June 30, 2016 and December 31, 2015 is summarized in the table above.

The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company’s credit policies and guidelines, and assesses the impact on fair values of its counterparties’ creditworthiness. The Company has entered into International Swap Dealers Association Master Agreements (“ISDA Agreements”) with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and its counterparties and brokers with rights of net settlement of gross commodity derivative assets against gross commodity derivative liabilities. The Company routinely exercises its contractual right to offset realized gains against realized losses when settling with derivative counterparties. The Company did not incur any losses due to counterparty bankruptcy filings during the three or six months ended June 30, 2016 or the year ended December 31, 2015.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Credit Risk Related Contingent Features in Derivatives

Certain commodity derivative instruments contain provisions that require the Company to either post additional collateral or immediately settle any outstanding liability balances upon the occurrence of a specified credit risk related event. These events, which are defined by the existing commodity derivative contracts, are primarily downgrades in the credit ratings of the Company and its affiliates. None of the Company's commodity derivative instruments were in a net liability position with respect to any individual counterparty at June 30, 2016 or December 31, 2015.

NOTE 4. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment includes the following (in thousands):

	June 30, 2016	December 31, 2015
Oil and natural gas properties:		
Subject to depletion	$2,088,394	$ 1,627,367
Not subject to depletion		
Incurred in 2016	401,377	—
Incurred in 2015	51,140	118,101
Incurred in 2014 and prior	486,603	500,693
Total not subject to depletion	939,120	618,794
Oil and natural gas properties, successful efforts method	3,027,514	2,246,161
Accumulated depreciation, depletion and impairment	(386,353)	(290,186)
Total oil and natural gas properties, net	2,641,161	1,955,975
Other property, plant and equipment	44,247	37,253
Less accumulated depreciation	(10,294)	(7,475)
Other property, plant and equipment, net	33,953	29,778
Total property, plant and equipment, net	$2,675,114	$ 1,985,753

Costs subject to depletion are proved costs and costs not subject to depletion are unproved costs and current drilling projects. At June 30, 2016 and December 31, 2015, the Company had excluded $939.1 million and $618.8 million, respectively, of capitalized costs from depletion.

As the Company's exploration and development work progresses and the reserves on the Company's properties are proven, capitalized costs attributed to the properties are subject to DD&A. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and natural gas reserves related to the associated reservoir. Depletion expense on capitalized oil and natural gas properties was $54.6 million and $43.1 million for the three months ended June 30, 2016 and 2015, respectively. Depletion expense on capitalized oil and natural gas properties was $102.5 million and $79.5 million for the six months ended June 30, 2016 and 2015, respectively. The Company had no exploratory wells in progress at June 30, 2016 or December 31, 2015.

NOTE 5. ACQUISITIONS OF OIL AND NATURAL GAS PROPERTIES

During the three months ended June 30, 2016 and 2015, the Company acquired $15.6 million and $8.0 million of leasehold acreage, respectively. The Company reflected the acquisition costs as part of costs not subject to depletion within its oil and natural gas properties.

During the six months ended June 30, 2016 and 2015, the Company acquired $28.5 million and $28.2 million of leasehold acreage, respectively. The Company reflected $27.7 million and $27.2 million of the acquisition costs as part of costs not subject to depletion and $0.8 million and $1.0 million as part of its cost subject to depletion within its oil and natural gas properties for the periods ended June 30, 2016 and 2015, respectively.

In addition, during the three and six months ended June 30, 2016 and 2015, the Company acquired certain oil and natural gas properties as described below. These acquisitions were accounted for using the acquisition method under Accounting Standards Codification ("ASC") Topic 805, "Business Combinations," which requires the acquired assets and liabilities to be recorded at fair values as of the respective acquisition dates.

During the three and six months ended June 30, 2016, the Company acquired 8,800 gross (6,269 net) acres located in Glasscock, Midland and Reagan Counties, Texas, along with net production of approximately 900 Boe/d from existing wells, from Riverbend Permian L.L.C. (“Riverbend”), for total cash consideration of $176.2 million (the “Riverbend Acquisition”). Randolph J. Newcomer, Jr., a member of the Company’s board of directors, is the President and Chief Executive Officer of Riverbend. As the transaction involved a related party, the Riverbend Acquisition was approved by the disinterested members of the Company’s board of directors. The Company reflected $37.7 million of the total consideration paid as part of its cost subject to depletion within its oil and natural gas properties and $138.5 million as unproved leasehold costs within its oil and natural gas properties for the periods ended June 30, 2016. No such transactions occurred during the three and six months ended June 30, 2015. The revenues and operating expenses attributable to the working interest acquisitions during the three and six months ended June 30, 2016 were not material.

During the three months ended June 30, 2016, the Company acquired, from unaffiliated individuals and entities, interests in certain oil and natural gas properties through a number of separate, individually negotiated transactions for total cash consideration of $148.1 million. The Company reflected $71.9 million of the total consideration paid as part of its cost subject to depletion within its oil and natural gas properties and $76.2 million as unproved leasehold costs within its oil and natural gas properties for the periods ended June 30, 2016. No such transactions occurred during the three months ended June 30, 2015. The revenues and operating expenses attributable to these acquisitions during the three months ended June 30, 2016 were not material.

During the six months ended June 30, 2016 and 2015, the Company acquired, from unaffiliated individuals and entities, interests in certain oil and natural gas properties through a number of separate, individually negotiated transactions for total cash consideration of $344.0 million and $1.6 million, respectively. The Company reflected $113.9 million and $1.3 million of the total consideration paid as part of its costs subject to depletion within its oil and natural gas properties for the periods ended June 30, 2016 and 2015, respectively. The Company reflected $230.1 million and $0.3 million as part of costs not subject to depletion within its oil and natural gas properties for the periods ended June 30, 2016 and 2015, respectively. The revenues and operating expenses attributable to these acquisitions during the six months ended June 30, 2016 and 2015 were not material.

On June 1, 2016, the Company exchanged certain unproved acreage and oil and natural gas properties in Upton and Reagan Counties, Texas, with a third party, with no gain or loss recognized. The Company acquired 3,054 gross (1,938 net) acres and 23 gross (15.5 net) vertical wells. In exchange, the Company divested 2,120 gross (2,078 net) acres and 20 gross (17.4 net) vertical wells.

As discussed in Note 14—Subsequent Events, on July 14, 2016, Minerals LLC acquired, from unaffiliated third-party sellers, certain mineral interests, surface rights and net production located in Pecos and Reeves Counties, Texas.

NOTE 6. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal.

The following table summarizes the changes in the Company’s asset retirement obligations for the six months ended June 30, 2016 (in thousands):

	June 30, 2016
Asset retirement obligations, beginning of period	$18,220
Additional liabilities incurred	1,707
Accretion expense	385
Liabilities settled upon plugging and abandoning wells	(6)
Disposition of wells	(534)
Revision of estimates	(2,964)
Asset retirement obligations, end of period	$16,808

PARSLEY ENERGY, INC. AND SUBSIDIARIES

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(Unaudited)

NOTE 7. DEBT

The Company's debt consists of the following (in thousands):

	June 30, 2016	December 31, 2015
Revolving Credit Agreement	$—	$ —
7.500% senior unsecured notes due 2022	550,000	550,000
6.250% senior unsecured notes due 2024	200,000	—
Capital leases	2,221	2,215
Total debt	752,221	552,215
Debt issuance costs on senior unsecured notes	(12,858)	(9,092)
Premium on senior unsecured notes	4,276	4,660
Less: current portion	(1,168)	(951)
Total long-term debt	$742,471	$ 546,832

Revolving Credit Agreement

As of June 30, 2016, the Borrowing Base (as defined therein) under the Revolving Credit Agreement was $525.0 million, with a commitment level of $525.0 million. The Borrowing Base was reduced from $575.0 million as of May 27, 2016 as a result of the Notes Offering. There were no borrowings outstanding and $0.3 million in letters of credit outstanding as of June 30, 2016, resulting in availability of $524.7 million.

As of June 30, 2016, letters of credit under the Revolving Credit Agreement had a weighted average interest rate of 1.5%.

6.250% Senior Unsecured Notes due 2024

On May 24, 2016, in connection with the Notes Offering discussed in Note 1—Organization and Nature of Operations, Parsley LLC, Finance Corp. and the guarantors entered into a purchase agreement with Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers. The net proceeds from the Notes Offering were $195.4 million, after deducting initial purchaser discounts and commissions and offering expenses. The Company used the net proceeds from the Notes Offering, along with the net proceeds from the May Offering, to fund the Minerals Acquisition discussed in Note 14—Subsequent Events, and the remaining net proceeds will be used to fund a portion of the Company's capital program and for general corporate purposes, including potential future acquisitions.

Covenant Compliance

The Revolving Credit Agreement and the indenture governing the Notes restrict our ability and the ability of certain of our subsidiaries to, among other things: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates; and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and no default or event of default (as defined in the indenture) has occurred and is continuing, many of the foregoing covenants pertaining to the Notes will be suspended. If the ratings on the Notes were to decline subsequently to below investment grade, the suspended covenants would be reinstated.

As of June 30, 2016, the Company was in compliance with all required covenants under the Revolving Credit Agreement and the indenture governing the Notes.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

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Principal Maturities of Debt

Principal maturities of debt outstanding at June 30, 2016 are as follows (in thousands):

2016	$561
2017	1,165
2018	438
2019	57
2020	—
Thereafter	750,000
Total	$752,221

Interest Expense

The following amounts have been incurred and charged to interest expense for the three and six months ended June 30, 2016 and 2015 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Cash payments for interest	$30	$748	$21,241	$22,010
Change in interest accrual	11,881	10,118	1,568	(262)
Amortization of deferred loan origination costs	623	540	1,211	1,034
Write-off of deferred loan origination costs	174	(82)	174	532
Amortization of bond premium	(192)	(191)	(383)	(382)
Other interest (income) expense	(317)	(34)	(418)	8
Total interest expense, net	$12,199	$11,099	$23,393	$22,940

NOTE 8. EQUITY

Earnings per Share

Basic earnings per share (“EPS”) measures the performance of an entity over the reporting period. Diluted earnings per share measures the performance of an entity over the reporting period while giving effect to all potentially dilutive common shares that were outstanding during the period. The Company uses the “if-converted” method to determine the potential dilutive effect of its Class B common stock, par value $0.01 per share (“Class B Common Stock”) and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock and restricted stock units. For the three and six months ended June 30, 2016 and 2015, Class B Common Stock, unvested restricted stock and restricted stock unit awards were not recognized in dilutive earnings per share calculations for that period as they would be antidilutive.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

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The following table reflects the allocation of net income to common stockholders and EPS computations for the periods indicated based on a weighted average number of common stock outstanding for the period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Basic EPS (in thousands, except per share data)				
Numerator:				
Basic net loss attributable to Parsley Energy, Inc. Stockholders	$(21,377)	$(19,129)	$(40,731)	$(36,153)
Denominator:				
Basic weighted average shares outstanding	158,662	108,058	147,313	104,684
Basic EPS attributable to Parsley Energy, Inc. Stockholders	$(0.13)	$(0.18)	$(0.28)	$(0.35)
Diluted EPS				
Numerator:				
Net loss attributable to Parsley Energy, Inc. Stockholders	(21,377)	(19,129)	(40,731)	(36,153)
Diluted net loss attributable to Parsley Energy, Inc. Stockholders	$(21,377)	$(19,129)	$(40,731)	$(36,153)
Denominator:				
Basic weighted average shares outstanding	158,662	108,058	147,313	104,684
Diluted weighted average shares outstanding [1]	158,662	108,058	147,313	104,684
Diluted EPS attributable to Parsley Energy, Inc. Stockholders	$(0.13)	$(0.18)	$(0.28)	$(0.35)

[1] There were 453,863 and 211,935 shares related to performance-based restricted stock units that could be converted to common shares in the future based on predetermined performance and market goals. These units were not included in the computation of EPS for the three and six months ended June 30, 2016 and 2015, respectively, because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the contingency period.

Noncontrolling Interest

As a result of the public offerings of Class A Common Stock discussed in Note 1—Organization and Nature of Operations, at June 30, 2016, the Company's ownership of Parsley LLC was 83.9% and other holders of PE Units' (the "PE Unit Holders") ownership of Parsley LLC was 16.1%. The Company has consolidated the financial position and results of operations of Parsley LLC and reflected that portion retained by the PE Unit Holders as a noncontrolling interest. Because the increase in the Company's ownership interest in Parsley LLC does not result in a change of control, the transaction is accounted for as an equity transaction under ASC Topic 810, "Consolidation," which requires that any differences between the amount by which the carrying value of the Company's basis in Parsley LLC is adjusted and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest.

The following table summarizes the noncontrolling interest income (loss):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands)			

Net income (loss) attributable to the noncontrolling interests of:				
Parsley LLC	$(6,085)	$(7,053)	$(12,441)	$(13,587)
Pacesetter Drilling, LLC	(26)	2	(7)	2
Total net loss attributable to noncontrolling interest	$(6,111)	$(7,051)	(12,448)	(13,585)

PARSLEY ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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NOTE 9. STOCK-BASED COMPENSATION

In connection with the Company's initial public offering (the "IPO") in May 2014, the Company adopted the Parsley Energy, Inc. 2014 Long Term Incentive Plan for employees, consultants, and directors of the Company who perform services for the Company. Refer to "Compensation Discussion and Analysis—Elements of Compensation —2014 Long-Term Incentive Plan" in the Company's Proxy Statement filed on Schedule 14A for the 2016 Annual Meeting of Stockholders for additional information related to this equity based compensation plan.

Performance Units

In February 2016, additional performance-based, stock-settled restricted stock units, which we refer to as performance units, were granted with a performance period of three years. The number of shares of Class A Common Stock actually vesting pursuant to these performance units depends on the performance of the Company's Class A Common Stock over the three-year performance period relative to the performance of the stock of predetermined peer group companies. The Company granted a target number of 241,928 performance units, but the conditions of the grants allow for an actual payout ranging between no payout and 200% of target. The fair value of such performance units was determined using a Monte Carlo simulation and will be amortized ratably over the next three years.

The following table summarized the Company's restricted stock, restricted stock unit, and performance unit activity for the six months ended June 30, 2016 (in thousands):

	Restricted Stock	Restricted Stock Units	Performance Units
Outstanding at January 1, 2016	661	513	212
Awards granted [1]	—	549	242
Vested	(68)	(11)	—
Forfeited	(8)	(5)	—
Outstanding at June 30, 2016	585	1,046	454
[1] Weighted average grant date fair value	$ —	$ 16.70	$ 25.82

Stock-based compensation expense related to restricted stock, restricted stock units, and performance units was $3.4 million and $2.1 million for the three months ended June 30, 2016 and 2015, respectively. Stock-based compensation expense related to restricted stock, restricted stock units, and performance units was $6.2 million and $3.8 million for the six months ended June 30, 2016 and 2015, respectively. There was approximately $25.5 million of unamortized compensation expense relating to outstanding restricted stock, restricted stock units, and performance units at June 30, 2016.

NOTE 10. INCOME TAXES

The Company is a corporation and it is subject to U.S. federal income tax. The tax implications of the IPO and the Company's concurrent corporate reorganization, and the tax impact of the Company's status as a taxable corporation subject to U.S. federal income tax have been reflected in the accompanying condensed consolidated financial statements. The effective combined U.S. federal and state income tax rate applicable to the Company as of June 30, 2016 was 27.8%. During the three months ended June 30, 2016 and 2015, the Company recognized an income tax benefit of $10.9 million and $10.2 million, respectively. During the six months ended June 30, 2016 and 2015, the Company recognized an income tax benefit of $20.5 million and $15.7 million, respectively. Total income tax expense for the three and six months ended June 30, 2016 differed from amounts computed by applying the U.S. federal statutory tax rate of 35% due primarily to the impact of loss attributable to noncontrolling ownership interests.

As a result of the public offerings of Class A Common Stock discussed in Note 1—Organization and Nature of Operations, the Company's statutory rate related to certain tax and book basis timing differences increased by 1%, calculated by multiplying the 2.9% increase in the Company's ownership of Parsley LLC by the Company's federal tax rate of 35%. As a result, the Company recorded additional deferred tax liability of $8.6 million during the three and six months ended June 30, 2016.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

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(Unaudited)

The Company early adopted ASU 2016-09 effective January 1, 2016, which resulted in a favorable adjustment for the net excess income tax benefits from stock-based compensation during the six months ended June 30, 2016. The adoption was on a prospective basis and therefore had no impact on prior years. The Company also recorded an adjustment to opening retained earnings of $0.1 million to recognize U.S. net operating loss carryforwards attributable to excess tax benefits on stock-based compensation that had not been previously recognized to additional paid in capital because they did not reduce income taxes payable.

NOTE 11. RELATED PARTY TRANSACTIONS

Well Operations

During the three and six months ended June 30, 2016 and 2015, several of the Company's directors, officers, 10% stockholders, their immediate family members, and entities affiliated or controlled by such parties ("Related Party Working Interest Owners") owned non-operated working interests in certain of the oil and natural gas properties that the Company operates. The revenues disbursed to such Related Party Working Interest Owners for the three months ended June 30, 2016 and 2015, totaled $0.8 million and $1.2 million, respectively. The revenues disbursed to such Related Party Working Interest Owners for the six months ended June 30, 2016 and 2015, totaled $1.6 million and $2.2 million, respectively.

As a result of this ownership, from time to time, the Company will be in a net receivable or net payable position with these individuals and entities. The Company does not consider any net receivables from these parties to be uncollectible.

Spraberry Production Services, LLC

As defined in Note 2—Basis of Presentation, the Company owns a 42.5% interest in SPS. Using the equity method of accounting results in transactions between the Company and SPS and its subsidiaries being accounted for as related party transactions. During the three months ended June 30, 2016 and 2015, the Company incurred charges totaling $1.0 million and $0.8 million, respectively, for services performed by SPS for the Company's well operations and drilling activities. During the six months ended June 30, 2016 and 2015, the Company incurred charges totaling $2.3 million and $2.6 million, respectively, for services performed by SPS for the Company's well operations and drilling activities.

Lone Star Well Service, LLC

The Company makes purchases of equipment used in its drilling operations from Lone Star Well Service, LLC ("Lone Star"), which is controlled by SPS. During the three months ended June 30, 2016 and 2015, the Company incurred charges totaling $1.7 million and $1.2 million, respectively, for services performed by Lone Star for the Company's wells operations and drilling activities. During the six months ended June 30, 2016 and 2015, the Company incurred charges totaling $2.8 million and $2.1 million, respectively, for services performed by Lone Star for the Company's wells operations and drilling activities.

Davis, Gerald & Cremer, P.C.

During the three months ended June 30, 2016 and 2015, the Company incurred charges totaling $0.1 million and $0.1 million, respectively, for legal services from Davis, Gerald & Cremer, P.C., of which the Company's director David H. Smith is a shareholder. During the six months ended June 30, 2016 and 2015, the Company incurred charges totaling $0.1 million and $0.2 million, respectively, for legal services from Davis, Gerald & Cremer, P.C.

Riverbend Acquisition

The Riverbend Acquisition discussed in Note 5—Acquisitions of Oil and Natural Gas Properties is considered a related party transaction. Randolph J. Newcomer, Jr., a member of the Company's board of directors, is the President and Chief Executive Officer of Riverbend. As the transaction involved a related party, the Riverbend Acquisition was approved by the disinterested members of the Company's board of directors. The Riverbend Acquisition closed on May 16, 2016.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

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Exchange Right

In accordance with the terms of the First Amended and Restated Limited Liability Company Agreement of Parsley LLC (the “Parsley LLC Agreement”), the PE Unit Holders generally have the right to exchange (the “Exchange Right”) their PE Units (and a corresponding number of shares of the Company’s Class B Common Stock) for shares of the Company’s Class A Common Stock at an exchange ratio of one share of Class A Common Stock for each PE Unit (and a corresponding share of Class B Common Stock) exchanged (subject to conversion rate adjustments for stock splits, stock dividends and reclassifications) or cash (pursuant to the Cash Option). As a PE Unit Holder exchanges its PE Units, the Company’s interest in Parsley LLC will be correspondingly increased. As described in Note 14—Subsequent Events, since June 30, 2016, certain PE Unit Holders elected to exchange an aggregate of 4.1 million PE Units (and a corresponding number of shares of Class B Common Stock) for an aggregate of 4.1 million shares of Class A Common Stock.

Tax Receivable Agreement

In connection with the IPO, on May 29, 2014, the Company entered into a Tax Receivable Agreement (the “TRA”) with Parsley LLC and certain holders of PE Units prior to the IPO (each such person a “TRA Holder”), including certain executive officers. This agreement generally provides for the payment by the Company of 85% of the net cash savings, if any, in U.S. federal, state, and local income tax or franchise tax that the Company actually realizes (or is deemed to realize in certain circumstances) in periods after the IPO as a result of (i) any tax basis increases resulting from the contribution in connection with the IPO by such TRA Holder of all or a portion of its PE Units to the Company in exchange for shares of Class A Common Stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A Common Stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash pursuant to the Cash Option) and (iii) imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, any payments the Company makes under the TRA. The term of the TRA commenced on May 29, 2014, and continues until all such tax benefits have been utilized or expired, unless the Company exercises its right to terminate the TRA. If the Company elects to terminate the TRA early, it would be required to make an immediate payment equal to the present value of the anticipated future tax benefits subject to the TRA (based upon certain assumptions and deemed events set forth in the TRA). In addition, payments due under the TRA will be similarly accelerated following certain mergers or other changes of control.

NOTE 12. SIGNIFICANT CUSTOMERS

For the six months ended June 30, 2016 and 2015, each of the following purchasers accounted for more than 10% of the Company’s revenue:

	Six Months Ended June 30,	
	2016	2015
Shell Trading (US) Company	35%	13%

BML, Inc.	22%	23%
Targa Pipeline Mid-Continent, LLC	13%	17%
TransOil Marketing, LLC	10%	13%

The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

NOTE 13. DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1:	Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
Level 2:	Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable as of the reporting date
Level 3:	Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. These assets and liabilities can include inventory, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, proved and unproved oil and natural gas properties, asset retirement obligations and other long-lived assets that are written down to fair value when they are impaired.

Proved oil and natural gas properties. During the three months ended June 30, 2016, continued suppression in management's long-term commodity price outlooks provided indications of possible impairment. As a result of management's assessments, during the three months ended June 30, 2016 and 2015, the Company did not recognize impairment charges to reduce the carrying values of any oil and natural gas properties to their estimated fair values.

The Company calculates the estimated fair values using a discounted future cash flow model. Management's assumptions associated with the calculation of discounted future cash flows include commodity prices based on NYMEX futures price strips (Level 1), as well as Level 3 assumptions including (i) pricing adjustments for differentials, (ii) production costs, (iii) capital expenditures, (iv) production volumes and (v) estimated reserves.

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves and (iv) results of future drilling activities.

PARSLEY ENERGY, INC. AND SUBSIDIARIES

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Financial Assets and Liabilities Measured at Fair Value

Commodity derivative contracts are marked-to-market each quarter and are thus stated at fair value in the accompanying condensed consolidated Balance Sheets and in Note 3—Derivative Financial Instruments. The fair values of the Company's commodity derivative instruments are classified as Level 2 measurements as they are calculated using 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 following summarizes the fair value of the Company's derivative assets and liabilities according to their fair value hierarchy as of the reporting dates indicated (in thousands):

	June 30, 2016			
	Level 1	Level 2	Level 3	Total
Commodity derivative contracts				
Assets:				
Short-term derivative instruments	$—	$27,662	$ —	$27,662
Long-term derivative instruments	—	20,171	—	20,171
Total derivative instrument - asset	—	47,833	—	47,833
Liabilities:				
Short-term derivative instruments	—	(18,672)	—	(18,672)
Long-term derivative instruments	—	(15,377)	—	(15,377)
Total derivative instruments - liability	—	(34,049)	—	(34,049)
Net commodity derivative asset	$—	$13,784	$ —	$13,784

	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Commodity derivative contracts				
Assets:				
Short-term derivative instruments	$—	$83,262	$ —	$83,262
Long-term derivative instruments	—	25,839	—	25,839
Total derivative instrument - asset	—	109,101	—	109,101
Liabilities:				
Short-term derivative instruments	—	(34,518)	—	(34,518)
Long-term derivative instruments	—	(15,142)	—	(15,142)
Total derivative instruments - liability	—	(49,660)	—	(49,660)
Net commodity derivative asset	$—	$59,441	$ —	$59,441

Financial Instruments Not Carried at Fair Value

The following table provides the fair value of financial instruments that are not recorded at fair value in the condensed consolidated balance sheets (in thousands):

	June 30, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Revolving Credit Agreement	$—	$—	$—	$—
7.500% senior unsecured notes due 2022	550,000	572,000	550,000	522,610
6.250% senior unsecured notes due 2024	200,000	204,500	—	—

The fair values of the Notes was determined using the June 30, 2016 quoted market price, a Level 1 classification in the fair value hierarchy. The book value of the Revolving Credit Agreement approximates its fair value as the interest rate is variable. As of June 30, 2016, there are no indicators for change in the Company’s market spread.

The Company has other financial instruments consisting primarily of cash and cash equivalents, accounts receivable, prepaid expenses, other current assets, accounts payable and accrued liabilities that approximate their fair value due to the short-term nature of these instruments.

NOTE 14. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through the date these financial statements were issued. The Company determined there were no events, other than as described below, that required disclosure or recognition in these financial statements.

Minerals Acquisition

On July 14, 2016, Minerals LLC acquired, from unaffiliated third-party sellers, mineral rights under 29,813 gross (29,813 net) acres, surface rights on 23,769 gross (23,769 net) of these acres and estimated net production of approximately 280 Boe/d at the time of the purchase and sale agreement from wells producing on these acres in Pecos and Reeves Counties, Texas (the “Minerals Acquisition”), for an aggregate purchase price of $280.2 million in cash, inclusive of a deposit of $28.1 million paid upon signing the purchase and sale agreement. The deposit is included in “Other current assets” on the condensed consolidated balance sheet and as an operating activity on the condensed consolidated statement of cash flows included in this Quarterly Report.

Exchange of Class B Common Stock and PE Units for Class A Common Stock

Since June 30, 2016, certain PE Unit Holders exercised their Exchange Right under the Parsley LLC Agreement and elected to exchange an aggregate of 4.1 million PE Units (and a corresponding number of shares of Class B Common Stock) for an aggregate of 4.1 million shares of Class A Common Stock. The Company exercised its call right under the Parsley LLC agreement and elected to issue Class A Common Stock to each of the exchanging PE Unit Holders in satisfaction of its election notices. As a result of the exchange, the Company’s interest in Parsley LLC will be correspondingly increased.

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

The following discussion and analysis should be read in conjunction with the accompanying financial statements and related notes. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed above in "Cautionary Note Regarding Forward-Looking Statements" and in our Annual Report on Form 10-K for the year ended December 31, 2015 (the "Annual Report") under the heading "Item 1A. Risk Factors," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

Parsley Energy, Inc. (either individually or together with its subsidiaries, as the context requires, "we," "us" or the "Company") was formed in December 2013. We are a holding company whose sole material asset as of June 30, 2016 consisted of 167,091,043 PE Units as of June 30, 2016. We are the managing member of Parsley Energy, LLC ("Parsley LLC") and are responsible for all operational, management and administrative decisions of Parsley LLC, and we consolidate the financial results of Parsley LLC and its subsidiaries.

We are an independent oil and natural gas company focused on the acquisition and development of unconventional oil and natural gas reserves in the Permian Basin. Our properties are located in the Midland and Delaware Basins and our activities have historically been focused on the vertical development of the Spraberry, Wolfberry and Wolftoka Trends of the Midland Basin. Our vertical wells in the Permian Basin are drilled into stacked pay zones that include the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline), Strawn, Atoka and Mississippian formations. We now focus predominantly on horizontal development drilling and expect to target various stacked pay intervals in the Spraberry, Wolfcamp, Upper Pennsylvanian (Cline) and Atoka shales.

Our Properties

At June 30, 2016, our acreage position was 160,058 gross (123,650 net) acres, which includes 111,993 gross (81,165 net) acres in the Midland Basin and 48,065 gross (42,485 net) acres in the Delaware Basin. The majority of our identified horizontal drilling locations are located in portions of Upton, Reagan, Midland, and Glasscock Counties, Texas. As of June 30, 2016, we operated 627 (379 net) vertical wells across our acreage in the Midland Basin. Since commencing our horizontal drilling program in 2013 through June 30, 2016, we have drilled and completed 109 gross (99 net) horizontal wells in the Midland Basin, of which 24 gross (22 net) and 40 gross (38 net) were completed during the three and six months ended June 30, 2016. We have also drilled and completed two gross (two net) horizontal wells in the Delaware Basin, of which one gross (one net) was drilled during the three months ended June 30, 2016. As of June 30, 2016, we operated 120 gross (106 net) horizontal wells. As of June 30, 2016, we had interests in 792 gross (500 net) producing wells across our properties and operated 97.1% of the wells in which we had an interest.

How We Evaluate Our Operations

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

production volumes;
realized prices on the sale of oil, natural gas, and NGLs, including the effect of our commodity derivative contracts;
lease operating expenses;
capital expenditures;
completions
activities; and
certain unit costs.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our oil, natural gas, and NGLs revenues do not include the effects of derivatives. For the three months ended June 30, 2016 and 2015, our revenues were derived 86% and 81%, respectively, from oil sales; 5% and 9%, respectively, from natural gas sales; and 9% and 10%, respectively, from NGLs sales. For the six months ended June 30, 2016 and 2015, our revenues were derived 85% and 81%, respectively, from oil sales; 7% and 10%, respectively, from natural gas sales; and 8% and 9%, respectively, from NGLs sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Production Volumes

The following table presents historical production volumes for our properties for the three and six months ended June 30, 2016 and 2015.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Oil (MBbls)	2,157	1,183	3,888	2,192
Natural gas (MMcf)	3,154	2,698	6,098	5,000
Natural gas liquids (MBoe)	566	392	991	702
Total (MBoe)	3,249	2,025	5,896	3,727
Average net production (Boe/d)	35,703	22,249	32,396	20,593

Production Volumes Directly Impact Our Results of Operations

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through the development of our properties as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions.

Realized Prices on the Sale of Oil, Natural Gas, and NGLs

Historically, oil, natural gas, and NGLs prices have been extremely volatile, and we expect this volatility to continue. Because our production consists primarily of oil, our revenues are more sensitive to price fluctuations in the price of oil than they are to fluctuations in NGLs or natural gas prices. During the three months ended June 30, 2016, WTI posted prices ranged from $35.70 to $51.23 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.90 to $2.92 per MMBtu. During the three months ended June 30, 2015, WTI posted prices ranged from $49.14 to $61.43 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.49 to $3.02 per MMBtu. During the six months ended June 30, 2016, WTI posted prices ranged from $26.21 to $51.23 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.64 to $2.92 per MMBtu. During the six months ended June 30, 2015, WTI posted prices ranged from $43.46 to $61.43 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.49 to $3.23 per MMBtu.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for a portion of our production, with an emphasis on our oil production. By removing a significant portion of price volatility associated with our oil production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil prices on our cash flow from operations for those periods. See “Item 3. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

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 oil or natural gas production.

Our positions hedging production as of June 30, 2016 were as follows:

Description and Production Period	VOLUME (Bbls)	SHORT PUT PRICE ($/Bbl)	LONG PUT PRICE ($/Bbl)	DIFFERENTIAL PRICE
Crude Oil Put Spreads:				
Jul 2016 - Sept 2016	75,000	$ 30.00	$ 40.00	
Jul 2016 - Dec 2016	2,010,000	$ 30.00	$ 40.00	
Jul 2016 - Dec 2016	1,200,000	$ 35.00	$ 50.00	
Jul 2016 - Dec 2016	450,000	$ 40.00	$ 55.00	
Aug 2016 - Dec 2016	250,000	$ 35.00	$ 50.00	
Oct 2016 - Dec 2016	180,000	$ 30.00	$ 40.00	
Jan 2017 - Jun 2017	1,200,000	$ 30.00	$ 37.50	
Jan 2017 - Jun 2017	600,000	$ 30.00	$ 40.00	
Jan 2017 - Jun 2017	1,434,000	$ 37.50	$ 52.50	
Jan 2017 - Dec 2017	900,000	$ 40.00	$ 55.00	
Jul 2017 - Dec 2017	450,000	$ 40.00	$ 50.00	
Jul 2017 - Dec 2017	1,050,000	$ 40.00	$ 55.00	
Jul 2017 - Dec 2017	264,000	$ 45.00	$ 55.00	
Total	10,063,000			
Crude Oil Basis Swaps:				
Jul 2016 - Dec 2016	390,000			$ (1.40)
Jul 2016 - Dec 2016	368,000			$ (0.35)
Jul 2016 - Dec 2016	368,000			$ (0.30)
Jul 2016 - Dec 2016	210,000			$ (1.40)
Jul 2016 - Dec 2016	180,000			$ (1.35)
Jan 2017 - Dec 2017	1,095,000			$ (0.40)
Jan 2017 - Dec 2017	1,095,000			$ (0.45)
Jan 2017 - Dec 2017	960,000			$ (1.65)
Jan 2017 - Dec 2017	600,000			$ (1.70)
Jan 2017 - Dec 2017	360,000			$ (1.60)
Jul 2017 - Dec 2017	180,000			$ (1.65)
Total	5,806,000			

Description and Production Period	VOLUME (Btu)	SHORT PUT PRICE ($/Btu)	LONG PUT PRICE ($/Btu)	SHORT CALL PRICE ($/Btu)
Natural Gas Three-Way Collars:				
Jan 2017 - Dec 2017	3,600,000	$ 2.40	$ 2.75	$ 4.00
Jan 2017 - Dec 2017	900,000	$ 2.35	$ 2.75	$ 4.05
Total	4,500,000			

We will recognize the following income (expense) in the line item Derivative loss on our condensed consolidated statements of operations from net cash premiums (paid) received on options that will settle during the following periods:

Q3 2016	$5,215
Q4 2016	5,575
Q1 2017	(4,918)
Q2 2017	(4,918)
Q3 2017	(6,044)
Q4 2017	(6,044)
Total	$(11,134)

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Impairment of Oil and Natural Gas Properties

Proved oil and natural gas properties are reviewed for impairment quarterly or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare the undiscounted cash flows to the carrying amount of the oil and natural gas properties, on a field-by-field basis, to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to estimated fair value.

As a result of suppressed commodity prices and their impact on our estimated future cash flows, we have continued to review our proved oil and natural gas properties for impairment. During the quarterly periods ended June 30, 2016 and 2015, we did not recognize an impairment of our proved oil and natural gas properties. At June 30, 2016, in our significant fields that comprise 99% of our carrying value, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and natural gas properties by an average of 138% and individually by a minimum of 50%.

The key assumptions used to determine the undiscounted future cash flows include, but are not limited to, future commodity prices, based on five-year WTI futures price index for oil and NGLs and five-year Henry Hub futures price index for natural gas, price differentials, future production estimates, estimated future capital expenditures and estimated future operating expenses. All inputs remained relatively consistent in the undiscounted future cash flow estimate from December 31, 2015 to June 30, 2016 except commodity price estimates. Future commodity pricing for oil and NGLs is based on five-year WTI futures prices, which increased 11% from December 31, 2015 to June 30, 2016, and on five-year Henry Hub futures prices, which increased 11% from December 31, 2015 to June 30, 2016. In terms of the increase in value of undiscounted cash flows from December 31, 2015 to June 30, 2016, the effect of the increase in pricing has been complemented by the addition of both proved developed and proved undeveloped reserves through our continued drilling and completion of previously unproved oil and natural gas properties and certain acquisitions.

As part of our period end reserves estimation process for future periods, we expect changes in the key assumptions used, which could be significant, including updates to future pricing estimates and differentials, future production estimates to align with our anticipated five-year drilling plan and changes in our capital costs and operating expense assumptions. There is a significant degree of uncertainty with the assumptions used to estimate future undiscounted cash flows due to, but not limited to the risk factors referred to in “Item 1A. Risk Factors” included in our Annual Report.

Any decrease in pricing, negative change in price differentials, increase in capital or operating costs could negatively impact the estimated undiscounted cash flows related to our proved oil and natural gas properties. A decrease of 26% in estimated future pricing of oil and natural gas commodities as of June 30, 2016 would have resulted in an estimated impairment of proved oil and natural gas properties of $57.4 million.

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Recent Transactions

Acquisitions of oil and natural gas properties. On April 4, 2016, we announced that we had entered into separate, individually negotiated agreements to acquire certain oil and natural gas interests located in the Southern Delaware and Midland Basins for an aggregate purchase price of $359.3 million (subject to customary purchase price adjustments).

Southern Delaware Basin acquisitions. The acquisitions announced on April 4, 2016 included the acquisition of 19,324 gross (14,197 net) acres in Reeves and Ward Counties, Texas, for an aggregate purchase price of $144.2 million (subject to customary purchase price adjustments). This total is primarily comprised of one acquisition. On March 11, 2016, we entered into a purchase and sale agreement with undisclosed third parties (collectively, the “Delaware Basin Sellers”) that provided for the sale and transfer by the Delaware Basin Sellers of their interests in 10,737 gross (9,821 net) acres located in Reeves and Ward Counties, Texas (the “Delaware Basin Acquisition”), for an aggregate purchase price of $136.0 million in cash (subject to customary purchase price adjustments). At the time of signing, the properties to be acquired had an estimated current net production of approximately 1,200 Boe/d from seven horizontal and 20 vertical producing wells. The Delaware Basin Acquisition closed on May 3, 2016.

Midland Basin acquisitions. The acquisitions announced on April 4, 2016 included the acquisition of 11,844 gross (8,711 net) acres in Midland, Upton, Reagan, and Glasscock Counties, Texas, for an aggregate purchase price of $215.1 million (the “Midland Basin Acquisition”). The $215.1 million total includes an acquisition of certain oil and natural gas interests from Riverbend Permian, L.L.C. (“Riverbend”). On April 1, 2016, we entered into a purchase and sale agreement (the “Riverbend Purchase Agreement”) with Riverbend. The Riverbend Purchase Agreement provided for the sale and transfer by Riverbend of its interests in 8,800 gross (6,269 net) acres located in Glasscock, Midland and Reagan Counties, Texas (the “Riverbend Acquisition”), for an aggregate purchase price of $176.2 million in cash (subject to customary purchase price adjustments). At the time of signing, the properties to be acquired had an estimated current net production of approximately 900 Boe/d from two horizontal and 37 vertical producing wells. Randolph J. Newcomer, Jr., a member of our board of directors, is the President and Chief Executive Officer of Riverbend. As the transaction involved a related party, the Riverbend Acquisition was approved by the disinterested members of our board of directors. The Riverbend Acquisition closed on May 16, 2016. The assets acquired from the Delaware Basin Acquisition and Midland Basin Acquisition also included six horizontal wells in various stages of drilling and completion.

Additionally, during the six months ended June 30, 2016, we entered into purchase and sale agreements to acquire additional working interests in wells through a number of separate, individually negotiated transactions for total cash consideration of $171.2 million, and we acquired $18.2 million of leasehold acreage as discussed in Note 5—Acquisitions of Oil and Natural Gas Properties to our condensed consolidated financial statements included elsewhere in this Quarterly Report.

Minerals acquisition. On July 14, 2016, Minerals LLC acquired, from unaffiliated third-party sellers, mineral rights under 29,813 gross (29,813 net) acres, surface rights on 23,769 gross (23,769 net) of these acres, and estimated net production at the time of the purchase and sale agreement of approximately 280 Boe/d from wells producing on these acres in Pecos and Reeves Counties, Texas (the “Minerals Acquisition”), for an aggregate purchase price of $280.2 million in cash, inclusive of a deposit of $28.1 million paid upon signing the purchase and sale agreement. The deposit is included in “Other current assets” on the condensed consolidated balance sheet and as an operating activity on the condensed consolidated statement of cash flows included in this Quarterly Report.

Public offerings of common stock. On April 4, 2016, we entered into an agreement to sell 20,987,500 shares of Class A Common Stock, par value $0.01 per share (“Class A Common Stock”) (including 2,737,500 shares issued pursuant to the underwriters’ option to purchase additional shares), at a price of $21.40 per share in an underwritten public offering (the “April Offering”). The April Offering closed on April 8, 2016 and resulted in gross proceeds of approximately $449.1 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately $433.2 million. A portion of the net proceeds from the April Offering were used to fund the acquisition of oil and natural gas interests in the Southern Delaware and Midland Basins, as described above. The remaining net proceeds will be used to fund a portion of our capital program and for general corporate purposes, including future acquisitions.

On May 23, 2016, we entered into an agreement to sell 9,487,500 shares of Class A Common Stock (including 1,237,500 shares issued pursuant to the underwriters’ option to purchase additional shares) at a price of $24.60 per share in an underwritten public offering (the “May Offering”). The May Offering closed on May 27, 2016 and resulted in gross proceeds of approximately $233.4 million to us and net proceeds, after deducting underwriting discounts and commissions and offering expenses, of approximately $226.2 million. The net proceeds from the May Offering, along with the net proceeds from the Notes Offering (as defined below), were used to fund the Minerals Acquisition. The remaining net proceeds will be used to fund a portion of our capital program and for general corporate purposes, including potential future acquisitions.

Private placement of Senior Notes. On May 24, 2016, Parsley LLC and Parsley Finance Corp., Parsley LLC's wholly owned subsidiary, as issuers, and certain subsidiaries of Parsley LLC, as guarantors, entered into an agreement to sell $200.0 million in aggregate principal amount of 6.250% senior notes due 2024 (the "2024 Notes") in an offering that was exempt from registration under the Securities Act (the "Notes Offering"). The Notes Offering closed on May 27, 2016 and resulted in gross proceeds of $200.0 million to us and net proceeds, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $195.4 million. The net proceeds from the Notes Offering, along with the net proceeds from the May Offering, were used to fund the aggregate purchase price for the Minerals Acquisition. The remaining net proceeds will be used to fund a portion of our capital program and for general corporate purposes, including potential future acquisitions.

Stock-Based Compensation

Stock-based compensation includes amortization expense related to grants from our 2014 Long Term Incentive Plan. Refer to Note 9—Stock-Based Compensation to our condensed consolidated financial statements included elsewhere in this Quarterly Report for additional discussion.

Drilling Activity

For the six months ended June 30, 2016 our capital expenditures for drilling and completions were $246.5 million, as compared to $400.9 million for all of fiscal year ended December 31, 2015.

The amount and timing of our future capital expenditures is largely discretionary and within our control. We could choose to defer a portion of planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

Results of Operations

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

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

	Three Months Ended June 30,			
	2016	2015	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$91,129	$63,418	$27,711	44 %
Natural gas sales	5,834	6,696	(862)	(13)%
Natural gas liquids sales	9,347	7,746	1,601	21 %
Total revenues	$106,310	$77,860	$28,450	37 %
Average realized prices [1]:				
Oil sales, without realized derivatives (per Bbls)	$42.25	$53.61	$(11.36)	(21)%
Oil sales, with realized derivatives (per Bbls)	47.49	60.78	(13.29)	(22)%
Natural gas, without realized derivatives (per Mcf)	1.85	2.48	(0.63)	(25)%
Natural gas, with realized derivatives (per Mcf)	1.85	2.65	(0.80)	(30)%
NGLs sales (per Boe)	16.51	19.76	(3.25)	(16)%
Average price per Boe, without realized derivatives	32.72	38.45	(5.73)	(15)%
Average price per Boe, with realized derivatives	36.20	42.86	(6.66)	(16)%
Production:				
Oil (MBbls)	2,157	1,183	974	82 %
Natural gas (MMcf)	3,154	2,698	456	17 %
Natural gas liquids (MBoe)	566	392	174	44 %
Total (MBoe)	3,249	2,025	1,224	60 %
Average daily production volume:				
Oil (Bbls)	23,703	13,000	10,703	82 %
Natural gas (Mcf)	34,659	29,648	5,011	17 %
Natural gas liquids (Boe)	6,220	4,308	1,912	44 %

Total (Boe/d)	35,703	22,249	13,454	60 %

(1) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

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 years indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil, natural gas and NGLs revenues.

	Three Months Ended June 30,	
	2016	2015
Average realized oil price ($/Bbl)	$42.25	$53.61
Average NYMEX ($/Bbl)	$43.47	$55.29
Differential to NYMEX	$(1.22)	$(1.68)
Average realized oil price to NYMEX percentage	97%	97%
Average realized natural gas price ($/Mcf)	$1.85	$2.48
Average NYMEX ($/Mcf)	$2.41	$2.76
Differential to NYMEX	$(0.56)	$(0.28)
Average realized natural gas to NYMEX percentage	77%	90%
Average realized NGLs price ($/Boe)	$16.51	$19.76
Average NYMEX ($/Boe)	$43.47	$55.29
Differential to NYMEX	$(26.96)	$(35.53)
Average realized NGLs price to NYMEX oil percentage	38%	36%

Oil revenues increased 44% to $91.1 million during the three months ended June 30, 2016 from $63.4 million during the three months ended June 30, 2015. The increase is attributable to an increase in oil production volumes of 974 MBbls offset by an $11.36 per barrel decrease in average oil prices. Of the overall changes in oil revenues, the increase in oil production volumes accounted for a positive change of $52.2 million, offset by the decrease in oil prices, which accounted for a negative change of $24.5 million.

Natural gas revenues decreased 13% to $5.8 million during the three months ended June 30, 2016 from $6.7 million during the three months ended June 30, 2015. The decrease is attributable to a $0.63 per Mcf decrease in average natural gas prices, offset by an increase in volumes sold of 456 MMcf. Of the overall changes in natural gas revenues, the decrease in price accounted for a negative change of $2.0 million, offset by increases in natural gas production volumes, which accounted for a positive change of $1.1 million.

NGLs revenues increased by 21% to $9.3 million during the three months ended June 30, 2016 from $7.7 million during the three months ended June 30, 2015. The increase is attributable to a 174 MBoe increase in NGLs production offset by a $3.25 per Boe decrease in average NGLs price. Of the overall changes in NGLs revenues, the increase in production volumes accounted for a positive change of $3.4 million and the increase in NGLs average price accounted for a negative change of $1.8 million.

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

	Three Months Ended June 30, 2016	2015	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$14,204	$18,464	$(4,260)	(23)%
Production and ad valorem taxes	6,407	5,431	976	18 %
Depreciation, depletion and amortization	55,988	44,407	11,581	26 %
General and administrative expenses (1)	17,307	14,083	3,224	23 %
Exploration costs	8,978	1,515	7,463	*
Acquisition costs	486	—	486	100 %
Accretion of asset retirement obligations	215	221	(6)	(3)%
Rig termination costs	—	3,870	(3,870)	*
Other operating expenses	1,651	23	1,628	*
Total operating expenses	$105,236	$88,014	$17,222	20 %
Expense per Boe:				
Lease operating expenses	$4.37	$9.12	$(4.75)	(52)%
Production and ad valorem taxes	1.97	2.68	(0.71)	(26)%
Depreciation, depletion and amortization	17.23	21.93	(4.70)	(21)%
General and administrative expenses (1)	5.33	6.95	(1.62)	(23)%
Exploration costs	2.76	0.75	2.01	*
Acquisition costs	0.15	—	0.15	*
Accretion of asset retirement obligations	0.07	0.11	(0.04)	(36)%
Rig termination costs	—	1.91	(1.91)	*
Other operating expenses	0.51	0.01	0.50	*
Total operating expenses per Boe	$32.39	$43.46	$(11.07)	(25)%

(1) General and administrative expenses include stock-based compensation expense of $3.4 million and $2.1 million for the three months ended June 30, 2016 and 2015, respectively.

* The percentage change is not considered meaningful.

Lease operating expenses. Lease operating expenses decreased 23% to $14.2 million during the three months ended June 30, 2016 from $18.5 million during the three months ended June 30, 2015. The decrease is primarily due to the cost reduction initiatives implemented by management. On a per Boe basis, lease operating expenses decreased to $4.37 per Boe during the three months ended June 30, 2016 from $9.12 per Boe during the three months ended June 30, 2015. The decrease in lease operating expenses per Boe is partially attributable to a greater portion of our production coming from horizontal wells. The decrease in lease operating expense per Boe is also partially attributable to a 60% increase in production during the same period.

Production and ad valorem taxes. Production and ad valorem taxes increased 18% to $6.4 million during the three months ended June 30, 2016 from $5.4 million during the three months ended June 30, 2015. In general, production and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior period commodity prices, whereas production taxes are based on current period commodity prices. Overall, production taxes increased by approximately $1.3 million, offset by a $0.3 million decrease in ad valorem taxes reflecting lower property assessments due to lower commodity prices.

Depreciation, depletion and amortization. DD&A expense increased $11.6 million, or 26%, to $56.0 million for the three months ended June 30, 2016 from $44.4 million for the three months ended June 30, 2015. The increase is attributable to a $601.4 million increase in costs subject to depletion and a 60% increase in production, offset by a 61% increase in total proved reserves and a 61% increase in proved developed reserves. On a per Boe basis, DD&A decreased $4.70 per Boe, or 21%, to $17.23 for the three months ended June 30, 2016 from $21.93 per Boe during the three months ended June 30, 2015 primarily due to the increase in production volumes, offset by the increase in reserves discussed above.

General and administrative expenses. General and administrative expenses increased 23% to $17.3 million during the three months ended June 30, 2016 from $14.1 million during the three months ended June 30, 2015 primarily due to higher payroll and stock-based compensation expenses associated with the hiring of additional employees to manage our growing asset base and increased production. On a per Boe basis, general and administrative expenses decreased $1.62 per Boe, or 23%, to $5.33 per Boe for the three months ended June 30, 2016 from $6.95 per Boe for the three months ended June 30, 2015.

Exploration costs. The following table provides a breakdown of exploration costs incurred for the periods indicated (in thousands):

	Three Months Ended June 30,	
	2016	2015
Leasehold abandonments	$5,524	$42
Idle drilling rig fees	1,331	—
Geological and geophysical costs	2,052	1,432
Unproved leasehold amortization	71	41
Total exploration costs	$8,978	$1,515

Exploration costs include idle drilling rig fees of $1.3 million that are not chargeable to our joint operations during the three months ended June 30, 2016. We will continue to incur idle drilling rig fees until the expiration of the applicable drilling rig contract in March 2017. There were no such expenses incurred during the three months ended June 30, 2015.

Our geological and geophysical (“G&G”) expenses consist of the costs of acquiring and processing seismic data, geophysical data and core analysis, primarily relating to increased geoscientific analysis of our Delaware Basin assets. During the three months ended June 30, 2016 and 2015, we obtained G&G data related to our Delaware Basin acreage.

We also recognized leasehold amortization expense during the three months ended June 30, 2016 and 2015, which relates to amortization of unproved leasehold costs.

We recognized leasehold abandonment expenses of approximately $5.5 million during the three months ended June 30, 2016, which primarily relates to expired acreage in Upton County, Texas. There were minimal expenses incurred during the three months ended June 30, 2015.

Acquisition costs. During the three months ended June 30, 2016, we incurred $0.5 million of acquisition costs, which include legal and other due diligence fees paid associated with the acquisitions described in Note 5—Acquisitions of Oil and Natural Gas Properties. There were no such costs incurred during the three months ended June 30, 2015.

Rig termination. During the three months ended June 30, 2015, we paid a total of $3.9 million in rig termination expenses, which is comprised of approximately $0.3 million related to the termination of drilling rig contracts entered into in 2014 and approximately $3.6 million for stacking fees associated with certain drilling rig contracts. There were no such expenses incurred during the three months ended June 30, 2016.

Other operating expenses. During the three months ended June 30, 2016 and 2015, we incurred operating expenses incurred during the normal course of business by our majority-owned subsidiary, Pacesetter Drilling, LLC.

Other income and expenses. The following table summarizes our other income and expenses for the periods indicated:

	Three Months Ended June 30, 2016	2015	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Interest expense, net	$(12,199)	$(11,099)	$(1,100)	(10)%
(Loss) gain on sale of property	(469)	1,031	(1,500)	(145)%
Derivative loss	(27,304)	(17,733)	(9,571)	(54)%
Other income, net	492	1,559	(1,067)	(68)%
Total other expense, net	$(39,480)	$(26,242)	$(13,238)	50 %

Interest expense, net. Interest expense, net increased 10% to $12.2 million during the three months ended June 30, 2016 from $11.1 million during the three months ended June 30, 2015. As discussed further above under “Recent Transactions,” we issued $200.0 million in aggregate principal amount of 2024 Notes, which increased our weighted average debt outstanding, resulting in an increase in interest expense.

(Loss) gain on sale of property. (Loss) gain on sale of property decreased $1.5 million to a loss of $0.5 million during the three months ended June 30, 2016 from a gain of $1.0 million during the three months ended June 30, 2015 due to the nature of the divestiture activity that occurred during the respective periods. During the three months ended June 30, 2016, we recognized a loss attributable to purchase price adjustments from prior acquisitions. During the three months ended June 30, 2015, we recognized a gain of $1.0 million associated with the divestiture of certain leasehold acreage.

Derivative loss. Derivative loss increased 54% to a loss of $27.3 million during the three months ended June 30, 2016, as compared to $17.7 million during the three months ended June 30, 2015, primarily as a result of favorable commodity price changes for operations and offset by increased hedging activities.

Other income, net. Other income, net decreased 68%, or $1.1 million, to $0.5 million during the three months ended June 30, 2016 as compared to $1.6 million during the three months ended June 30, 2015. The decrease is primarily attributable to a $1.1 million decrease in in license fee income, which is related to licensing of certain geological and geophysical seismic data.

Income Tax Benefit

The effective combined U.S. federal and state income tax rate applicable to the Company as of June 30, 2016 was 27.8%. During the three months ended June 30, 2016, we recognized a tax benefit of $10.9 million, an increase of $0.7 million, or 7% as compared to the $10.2 million tax benefit we recognized during the three months ended June 30, 2015. This increase was attributable to the corresponding increase in net losses during the applicable periods, as discussed above.

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

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

	Six Months Ended June 30,			
	2016	2015	$ Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$143,160	$107,106	$36,054	34 %
Natural gas sales	11,377	13,652	(2,275)	(17)%
Natural gas liquids sales	14,041	12,313	1,728	14 %
Total revenues	$168,578	$133,071	$35,507	27 %
Average realized prices [1]:				
Oil sales, without realized derivatives (per Bbls)	$36.82	$48.86	$(12.04)	(25)%
Oil sales, with realized derivatives (per Bbls)	47.15	58.45	(11.30)	(19)%
Natural gas, without realized derivatives (per Mcf)	1.87	2.73	(0.86)	(32)%
Natural gas, with realized derivatives (per Mcf)	1.87	2.91	(1.04)	(36)%
NGLs sales (per Boe)	14.17	17.54	(3.37)	(19)%
Average price per Boe, without realized derivatives	28.59	35.70	(7.11)	(20)%
Average price per Boe, with realized derivatives	35.40	41.58	(6.18)	(15)%
Production:				
Oil (MBbls)	3,888	2,192	1,696	77 %
Natural gas (MMcf)	6,098	5,000	1,098	22 %
Natural gas liquids (MBoe)	991	702	289	41 %
Total (MBoe)	5,896	3,727	2,169	58 %
Average daily production volume:				
Oil (Bbls)	21,363	12,110	9,253	76 %
Natural gas (Mcf)	33,505	27,624	5,881	21 %
Natural gas liquids (Boe)	5,445	3,878	1,567	40 %
Total (Boe/d)	32,396	20,593	11,803	57 %

(1) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

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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 years indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil, natural gas and NGLs revenues.

	Six Months Ended June 30,	
	2016	2015
Average realized oil price ($/Bbl)	$36.82	$48.86
Average NYMEX ($/Bbl)	$38.72	$52.45
Differential to NYMEX	$(1.90)	$(3.59)
Average realized oil price to NYMEX percentage	95 %	93 %
Average realized natural gas price ($/Mcf)	$1.87	$2.73
Average NYMEX ($/Mcf)	$2.28	$2.86
Differential to NYMEX	$(0.41)	$(0.13)
Average realized natural gas to NYMEX percentage	82 %	95 %
Average realized NGLs price ($/Boe)	$14.17	$17.54
Average NYMEX ($/Boe)	$38.72	$52.45
Differential to NYMEX	$(24.55)	$(34.91)
Average realized NGLs price to NYMEX oil percentage	37 %	33 %

Oil revenues increased 34% to $143.2 million during the six months ended June 30, 2016 from $107.1 million during the six months ended June 30, 2015. The increase is attributable to an increase in oil production volumes of 1,696 MBbls offset by a $12.04 per barrel decrease in average oil prices. Of the overall changes in oil revenues, the increase in oil production volumes accounted for a positive change of $82.9 million, offset by the decrease in oil prices, which accounted for a negative change of $46.8 million.

Natural gas revenues decreased 17% to $11.4 million during the six months ended June 30, 2016 from $13.7 million during the six months ended June 30, 2015. The decrease is attributable to a $0.86 per Mcf decrease in average natural gas prices, offset by an increase in volumes sold of 1,098 MMcf. Of the overall changes in natural gas revenues, the decrease in price accounted for a negative change of $5.3 million, offset by increases in natural gas production volumes, which accounted for a positive change of $3.0 million.

NGLs revenues increased by 14% to $14.0 million during the six months ended June 30, 2016 from $12.3 million during the six months ended June 30, 2015. The increase is attributable to a 289 MBoe increase in NGLs production offset by a $3.37 per Boe decrease in average NGLs price. Of the overall changes in NGLs revenues, the increase in production volumes accounted for a positive change of $5.1 million and the increase in NGLs average price accounted for a negative change of $3.4 million.

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

	Six Months Ended June 30, 2016	2015	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$28,102	$34,862	$(6,760)	(19)%
Production and ad valorem taxes	10,602	9,926	676	7%
Depreciation, depletion and amortization	105,372	81,788	23,584	29%
General and administrative expenses [(1)]	36,606	27,064	9,542	35%
Exploration costs	9,666	4,734	4,932	*
Acquisition costs	486	—	486	100%
Accretion of asset retirement obligations	385	470	(85)	(18)%
Rig termination costs	—	8,970	(8,970)	(100)%
Other operating expenses	2,547	23	2,524	*
Total operating expenses	$193,766	$167,837	$25,929	15%
Expense per Boe:				
Lease operating expenses	$4.77	$9.35	$(4.58)	(49)%
Production and ad valorem taxes	1.80	2.66	(0.86)	(32)%
Depreciation, depletion and amortization	17.87	21.94	(4.07)	(19)%
General and administrative expenses [(1)]	6.21	7.26	(1.05)	(14)%
Exploration costs	1.64	1.27	0.37	29%
Acquisition costs	0.08	—	0.08	100%
Accretion of asset retirement obligations	0.07	0.13	(0.06)	(46)%
Rig termination costs	—	2.41	(2.41)	(100)%
Other operating expenses	0.43	0.01	0.42	*
Total operating expenses per Boe	$32.87	$45.03	$(12.16)	(27)%

(1) General and administrative expenses include stock-based compensation expense of $6.2 million and $3.8 million for the six months ended June 30, 2016 and 2015, respectively.

* The percentage change is not considered meaningful.

Lease operating expenses. Lease operating expenses decreased 19% to $28.1 million during the six months ended June 30, 2016 from $34.9 million during the six months ended June 30, 2015. The decrease is primarily due to the cost reduction initiatives implemented by management. On a per Boe basis, lease operating expenses decreased to $4.77 per Boe during the six months ended June 30, 2016 from $9.35 per Boe during the six months ended June 30, 2015. The decrease in lease operating expenses per Boe is partially attributable to a greater portion of our production coming from horizontal wells. The decrease in lease operating expense per Boe is also partially attributable to a 58% increase in production during the same period.

Production and ad valorem taxes. Production and ad valorem taxes increased 7% to $10.6 million during the six months ended June 30, 2016 from $9.9 million during the six months ended June 30, 2015. Overall, production taxes increased by approximately $1.6 million, reflecting increased production volumes, offset by a $0.9 million decrease in ad valorem taxes due to lower property assessments due to lower commodity prices.

Depreciation, depletion and amortization. DD&A expense increased $23.6 million, or 29%, to $105.4 million for the six months ended June 30, 2016 from $81.8 million for the six months ended June 30, 2015. The increase is attributable to a $601.4 million increase in costs subject to depletion and a 58% increase in production, offset by a 61% increase in total proved reserves and a 61% increase in proved developed reserves. On a per Boe basis, DD&A decreased $4.07 per Boe, or 19%, to $17.87 for the six months ended June 30, 2016 from $21.94 per Boe during the six months ended June 30, 2015 primarily due to the increase in production volumes, offset by the increase in reserves discussed above.

General and administrative expenses. General and administrative expenses increased 35% to $36.6 million during the six months ended June 30, 2016 from $27.1 million during the six months ended June 30, 2015 primarily due to higher payroll and stock-based compensation expenses. In addition, we incurred increased rent expense for our new corporate headquarters as well as increased professional fees and consultant costs associated with ongoing public company operations. On a per Boe basis, general and administrative expenses decreased $1.05 per Boe, or 14%, to $6.21 per Boe for the six months ended June 30, 2016 from $7.26 per Boe for the six months ended June 30, 2015.

Exploration costs. The following table provides a breakdown of exploration costs incurred for the periods indicated (in thousands):

	Six Months Ended June 30,	
	2016	2015
Leasehold abandonments	$5,524	$1,739
Idle drilling rig fees	1,331	—
Geological and geophysical costs	2,658	2,936
Unproved leasehold amortization	153	59
Total exploration costs	$9,666	$4,734

Exploration costs include idle drilling rig fees of $1.3 million that are not chargeable to our joint operations during the six months ended June 30, 2016. We will continue to incur idle drilling rig fees until the expiration of the applicable drilling rig contract in March 2017. There were no such expenses incurred during the six months ended June 30, 2015.

We recognized leasehold amortization expense during the six months ended June 30, 2016 and 2015, which relates to amortization of unproved leasehold costs.

We recognized leasehold abandonment expenses of approximately $5.5 million and $1.7 million during the six months ended June 30, 2016 and 2015, respectively. The $5.5 million and $1.7 million of leasehold abandonment expense recognized during the six months ended June 20, 2016 and 2015, respectively, primarily relates to expired acreage and expiring acreage determined to be outside of our economically productive reserves.

Acquisition costs. During the six months ended June 30, 2016, we incurred $0.5 million of acquisition costs, which include legal and other due diligence fees paid associated with the acquisitions described in Note 5—Acquisitions of Oil and Natural Gas Properties. There were no such costs incurred during the six months ended June 30, 2015.

Rig termination. During the six months ended June 30, 2015, we paid a total of $9.0 million in rig termination expenses, which is comprised of approximately $4.4 million related to the termination of drilling rig contracts entered into in 2014 and approximately $4.6 million for stacking fees associated with certain drilling rig contracts. There were no such expenses incurred during the six months ended June 30, 2016.

Other operating expenses. During the six months ended June 30, 2016 and 2015 we incurred other operating expenses, which are incurred during the normal course of business by our majority-owned subsidiary, Pacesetter Drilling, LLC.

Other income and expenses. The following table summarizes our other income and expenses for the periods indicated:

	Six Months Ended June 30,			
	2016	2015	$ Change	% Change
Other income (expense) (in thousands,				

except percentages):				
Interest expense, net	$(23,393)	$(22,940)	$(453)	(2)%
(Loss) gain on sale of property	(119)	1,031	(1,150)	*
Derivative loss	(25,216)	(10,591)	(14,625)	*
Other income, net	251	1,838	(1,587)	(86)%
Total other expense, net	$(48,477)	$(30,662)	$(17,815)	(58)%

* The percentage change is not considered meaningful.

Interest expense, net. Interest expense, net remained consistent with a slight increase to $23.4 million during the six months ended June 30, 2016 from $22.9 million during the six months ended June 30, 2015. The change is attributable to varying weighted average debt balances over the comparable periods.

(Loss) gain on sale of property. (Loss) gain on sale of property decreased $1.2 million to a loss of $0.1 million during the six months ended June 30, 2016 from a gain of $1.0 million during the six months ended June 30, 2015 due to the nature of the divestiture activity that occurred during the respective periods. During the six months ended June 30, 2016, we recognized a loss of $0.1 million attributable to purchase price adjustments from prior acquisitions. During the six months ended June 30, 2015, we recognized a gain of $1.0 million associated with the divestiture of certain leasehold acreage.

Derivative loss. Derivative loss increased $14.6 million to $25.2 million during the six months ended June 30, 2016, as compared to $10.6 million during the six months ended June 30, 2015, primarily as a result of favorable commodity price changes for operations offset by increased hedging activities.

Other income, net. Other income, net decreased 86%, or $1.6 million, to $0.3 million during the six months ended June 30, 2016 as compared to $1.8 million during the six months ended June 30, 2015. The decrease is attributable to a $1.2 million decrease in geological and geophysical license fee income, and a $1.1 million decrease in our equity investment income. This decrease is offset by a $0.7 million increase in gathering system income.

Income Tax Benefit

The effective combined U.S. federal and state income tax rate applicable to the Company as of June 30, 2016 was 27.8%. During the six months ended June 30, 2016, we recognized a tax benefit of $20.5 million, an increase of $4.8 million, or 31% as compared to the $15.7 million tax benefit we recognized during the six months ended June 30, 2015. This increase was attributable to the corresponding increase in net losses during the applicable periods, as discussed above.

Capital Requirements and Sources of Liquidity

For the six months ended June 30, 2016, our aggregate drilling and completion capital expenditures, including facilities, were $246.5 million. During the year ended December 31, 2015, our aggregate drilling and completion capital expenditures were $400.9 million. These capital expenditure totals exclude acquisitions.

Our current 2016 capital budget is approximately $460 million to $510 million, which has increased from our previously disclosed capital budget of $410 million to $460 million due to an increase in expected activity. Our capital budget excludes any amounts that may be paid for acquisitions. The amount and timing of 2016 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2016 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Based upon our current oil and natural gas price expectations for the remainder of the 2016 fiscal year, we believe that our cash on hand, cash flow from operations, and borrowings under our amended and restated credit agreement with Wells Fargo Bank, National Association, as administrative agent (as amended, the “Revolving Credit Agreement”) will be sufficient to fund our operations through 2016. 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 required to more fully develop our properties. As of June 30, 2016, our liquidity was as follows (in thousands):

Cash and cash equivalents	$441,024
Revolving Credit Agreement availability	524,750
Liquidity	$965,774

Pro forma for the $252.1 million of cash paid for the Minerals Acquisition, our liquidity as of June 30, 2016, was approximately $713.6 million.

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. For example, we expect a portion of our future capital expenditures to be financed with cash flows from operations derived from wells drilled in drilling locations not associated with proved reserves on our December 31, 2015 reserve report. The failure to achieve anticipated production and cash flows from operations from such wells could result in a reduction in future capital spending. Further, our capital expenditure budget for 2016 does not allocate any amounts for acquisitions of oil and natural gas 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 traditional reserve base borrowings, 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 programs, 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 replace our reserves. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	Six Months Ended June 30,	
	2016	2015
Net cash provided by operating activities	$51,805	$78,627
Net cash used in investing activities	(807,975)	(255,938)
Net cash provided by financing activities	854,110	147,859

Cash flows from operating activities. Net cash provided by operating activities was approximately $51.8 million and $78.6 million for the six months ended June 30, 2016 and 2015, respectively. Net cash provided by operating activities decreased from the period ending June 30, 2015 to June 30, 2016 primarily due to a $76.4 million decrease related to changes in working capital, offset by a $35.5 million increase in total revenues. Cash provided by operating activities is also impacted by the prices received for oil, natural gas and NGLs sales and levels of production volumes.

Cash flows from investing activities. Net cash used in investing activities was approximately $808.0 million and $255.9 million for the six months ended June 30, 2016 and 2015, respectively. The increased amount of cash used in investing activities was due primarily to the $519.0 million increase in acquisition costs related to oil and natural gas properties during the six months ended June 30, 2016 over the six months ended June 30, 2015. Please refer to Note 5—Acquisitions of Oil and Natural Gas Properties to our condensed consolidated financial statements included elsewhere in this Quarterly Report for additional discussion related to acquisitions.

Cash flows from financing activities. Net cash provided by financing activities was $854.1 million and $147.9 million for the six months ended June 30, 2016 and 2015, respectively. Net cash from financing activities increased in the period ending June 30, 2016 primarily due increased debt and equity related activity. During the six months ended June 30, 2016, we received net proceeds from the April and May Offerings of $659.4 million and gross proceeds from the Notes Offering of $200.0 million. During the six months ended June 30, 2015, we received proceeds of $224.0 million from a private placement of our Class A Common Stock, which was offset by a net debt reduction of $75.3 million.

Capital Sources

Revolving Credit Agreement. See Note 7—Debt to our condensed consolidated financial statements included elsewhere in this Quarterly Report for information regarding the Revolving Credit Agreement.

7.500% Senior Unsecured Notes due 2022. See Note 7—Debt to our condensed consolidated financial statements included elsewhere in this Quarterly Report for information regarding our 7.500% senior notes due 2022 (the “ 2022 Notes” and, together with the 2024 Notes, the “Notes”).

6.250% Senior Unsecured Notes due 2024. See Note 7—Debt to our condensed consolidated financial statements included elsewhere in this Quarterly Report for information regarding our 2024 Notes.

Derivative activity. We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to continue our historical practice of entering into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering a portion of our projected oil production.

Working Capital

Our working capital totaled $365.0 million and $259.8 million at June 30, 2016 and December 31, 2015, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $441.0 million and $343.1 million at June 30, 2016 and December 31, 2015, respectively. The $97.9 million decrease in cash is primarily attributable to the acquisitions described in Note 5—Acquisitions of Oil and Natural Gas Properties to our condensed consolidated financial statements included elsewhere in this Quarterly Report as well as the increase in operating expenses in conjunction with the slight decrease in revenues, which is largely attributable to the $11.30 decrease in the average price per barrel of oil, including the effects of derivatives, from December 31, 2015 to June 30, 2016. Due to the costs incurred related to our drilling program, we may incur additional working capital deficits in the future. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Critical Accounting Policies and Estimates

There have not been any material changes during the six months ended June 30, 2016, to the methodology applied by management for critical accounting policies previously disclosed in our Annual Report, except as described below. Please read "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" in our Annual Report for further description of the Company's critical accounting policies.

We adopted Accounting Standards Update ("ASU") 2015-03, Interest - Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, effective January 1, 2016. This standard requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. To the extent that there are no borrowings under the Revolving Credit Agreement, the related deferred loan costs will continue to be classified as an asset. The guidance required retrospective application in the condensed consolidated financial statements. We had no borrowings outstanding under the Revolving Credit Agreement at June 30, 2016 and December 31, 2015, as such, approximately $1.7 million and $2.3 million, respectively, of deferred loan costs related to the Revolving Credit Agreement are included in "Other noncurrent assets" on the condensed consolidated balance sheets and as an operating activity on the condensed consolidated statement of cash flows included in this Quarterly Report. Our Notes are presented net of approximately $12.9 million and $9.1 million of deferred loan costs at June 30, 2016 and December 31, 2015, respectively.

We adopted ASU 2016-09, Compensation—Stock Compensation (Topic 718)—Improvements to Employee Share-Based Payment Accounting, effective January 1, 2016. This ASU is intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, including interim periods within those annual periods, and early application is permitted as of the beginning of an interim or annual reporting period. The ASU did not have a material effect on our financial statements and related disclosures.

Off-Balance Sheet Arrangements

As of June 30, 2016, we had no material off-balance sheet arrangements.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices 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 the prices of the commodities we sell. 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 major market risk exposure is in the pricing that we receive for our oil production. Pricing for oil has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations. For a description of our open positions at June 30, 2016, see Note 3—Derivative Financial Instruments to our condensed consolidated financial statements included elsewhere in this Quarterly Report.

We do not require collateral from our counterparties for entering into derivative instruments, so in order to mitigate the credit risk associated with such derivative instruments, we enter into an International Swap Dealers Association Master Agreement ("ISDA Agreement") with each of our counterparties. The ISDA Agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each derivative transaction between the counterparty and us separately, the ISDA Agreement enables the counterparty and us to aggregate all trades under such agreement and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (i) default by a counterparty under a single trade can trigger rights to terminate all trades with such counterparty that are subject to the ISDA Agreement; and (ii) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

As of June 30, 2016, the fair market value of our oil derivative contracts was a net asset of $13.8 million. Based on our open oil derivative positions at June 30, 2016, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $9.5 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $13.9 million. Please read "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Realized Prices on the Sale of Oil, Natural Gas, and NGLs."

Counterparty Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. We plan to continue to evaluate the credit standings of our counterparties in a similar manner.

The majority of our derivative contracts currently in place are with lenders under our Revolving Credit Agreement, who have investment grade ratings.

Interest Rate Risk

Our market risk exposure related to changes in interest rates relates primarily to debt obligations. We are exposed to changes in interest rates as a result of our Revolving Credit Agreement, and the terms of our Revolving Credit Agreement require us to pay higher interest rate margins as we utilize a larger percentage of our available commitments. As of June 30, 2016, however, we had no outstanding borrowings related to our Revolving Credit Agreement, and therefore an increase in interest rates will not result in increased interest expense until such time that we determine to make borrowings under our Revolving Credit Agreement.

Item 4. Controls and Procedures

As required by Rule 13a-15(b) of 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) under the Exchange Act) as of June 30, 2016. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2016, at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) during the three months ended June 30, 2016, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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. 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, you should carefully consider the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" included in our Annual Report and the risk factors and other cautionary statements contained in our other SEC filings, which could materially affect our businesses, 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 future results. There have been no material changes in our risk factors from those described in our Annual Report or our other SEC filings.

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

The following sets forth information with respect to our repurchases of shares of Class A Common Stock during the second quarter of 2016:

Period	Total number of shares purchased [1]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
April 2016	—	$ —	—	$ —
May 2016	4,066	$ 25.94	—	$ —
June 2016	5,495	$ 26.63	—	$ —
Total	9,561	$ 26.33	—	$ —

[1] Consists of shares of Class A Common Stock repurchased from employees in order for the employee to satisfy tax withholding payments related to stock-based awards that vested during the period.

Item 6. Exhibits

The exhibits required to be filed by Item 6 are set forth in the Exhibit Index accompanying this Quarterly Report.

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.

PARSLEY ENERGY, INC.

August 5, 2016 By: /s/ Bryan Sheffield
Bryan Sheffield
Chairman, President and Chief Executive Officer

Principal Executive Officer

August 5, 2016 By: /s/ Ryan Dalton
Ryan Dalton
Vice President—Chief Financial Officer

Principal Accounting and Financial Officer

EXHIBIT INDEX

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
3.2	Amended and Restated Bylaws of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
4.1	Indenture, dated May 27, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 27, 2016).
10.1	Purchase Agreement, dated May 24, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 27, 2016).
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

† Management contract or compensatory plan or arrangement.
* Filed herewith.
** Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this Quarterly Report on Form 10-Q 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, except to the extent that the registrant specifically incorporates it by reference.