Parsley Energy, Inc.
Form 10-Q
August 08, 2018

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, 2018
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-36463

PARSLEY ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	46-4314192
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
303 Colorado Street, Suite 3000 Austin, Texas	78701
(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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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 8, 2018, the registrant had 279,700,281 shares of Class A common stock and 37,076,994 shares of Class B common stock outstanding.

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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 carefully consider the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2017 (the "Annual Report") and the risk factors and other cautionary statements contained in 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 by the forward-looking statements.

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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) Developed acreage. Acreage spaced or assigned to productive wells, excluding undrilled acreage held by production under the terms of the lease.

(9) Economically producible. A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For a complete definition of economically producible, refer to the SEC’s Regulation S-X, Rule 4-10(a)(10).

(10) 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.

(11) 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 costs 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 defense, 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.

(12) 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.

(13) 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. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(14) Formation. A layer of rock which has distinct characteristics that differ from nearby rock.
(15) GAAP. Accounting principles generally accepted in the United States.
(16) Gross acres or gross wells. The total acres or wells, as the case may be, in which an entity owns a working interest.
(17) Horizontal drilling. A drilling technique where a well is drilled vertically to a certain depth and then drilled laterally within a specified target zone.
(18) Identified drilling locations. Potential drilling locations specifically identified by our management based on evaluation of applicable geologic and engineering data accrued over our multi-year historical drilling activities.
(19) 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.
(20) LIBOR. London Interbank Offered Rate.
(21) MBbl. One thousand barrels of crude oil, condensate or NGLs.
(22) MBoe. One thousand barrels of oil equivalent.
(23) Mcf. One thousand cubic feet of natural gas.
(24) MMBtu. One million British thermal units.
(25) MMcf. One million cubic feet of natural gas.
(26) 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.
(27) 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 a 50% interest in 100 gross acres owns 50 net acres.
(28) NYMEX. The New York Mercantile Exchange.
(29) Operator. The entity responsible for the exploration, development and production of a well or lease.
(30) PE Units. The single class of units that represents all of the membership interests in Parsley Energy, LLC.
(31) 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.
(32) 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, 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).
(33) 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. The following rules apply to PUDs:

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(i) 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;

(ii) 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; and

(iii) 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.

(34) 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).

(35) Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new or existing reservoirs in an attempt to establish new production or increase existing production.

(36) 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.

(37) 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.

(38) 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.

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

(40) 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.

(41) Undeveloped acreage. Leased 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.

(42) Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

(43) 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.

(44) Workover. Operations on a producing well to restore or increase production.

(45) 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.

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PART 1: FINANCIAL INFORMATION
Item 1: Financial Statements
PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2018	December 31, 2017
	(In thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$201,702	$554,189
Short-term investments	99,704	149,283
Accounts receivable:		
Joint interest owners and other	29,721	42,174
Oil, natural gas and NGLs	178,593	123,147
Related parties	241	388
Short-term derivative instruments, net	42,780	41,957
Assets held for sale	—	1,790
Other current assets	41,784	6,558
Total current assets	594,525	919,486
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	9,434,570	8,551,314
Accumulated depreciation, depletion and impairment	(1,074,499)	(822,459)
Total oil and natural gas properties, net	8,360,071	7,728,855
Other property, plant and equipment, net	146,517	106,587
Total property, plant and equipment, net	8,506,588	7,835,442
NONCURRENT ASSETS		
Assets held for sale, net	—	14,985
Long-term derivative instruments, net	30,837	15,732
Other noncurrent assets	7,493	7,553
Total noncurrent assets	38,330	38,270
TOTAL ASSETS	$9,139,443	$8,793,198
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$426,677	$407,698
Revenue and severance taxes payable	134,740	109,917
Current portion of long-term debt	2,462	2,352
Short-term derivative instruments, net	68,242	84,919
Current portion of asset retirement obligations	7,754	7,203
Total current liabilities	639,875	612,089
NONCURRENT LIABILITIES		
Liabilities related to assets held for sale	—	405
Long-term debt	2,180,559	2,179,525
Asset retirement obligations	20,853	19,967
Deferred tax liability	100,392	21,403
Payable pursuant to tax receivable agreement	62,681	58,479
Long-term derivative instruments, net	34,936	20,624
Total noncurrent liabilities	2,399,421	2,300,403

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, 280,106,940 shares issued and 279,518,737 shares outstanding at June 30, 2018 and 252,419,601 shares issued and 252,260,300 shares outstanding at December 31, 2017	2,801	2,524
Class B, $0.01 par value, 125,000,000 shares authorized, 37,251,738 and 62,128,157 shares issued and outstanding at June 30, 2018 and December 31, 2017	373	622
Additional paid in capital	5,123,089	4,666,365
Retained earnings	245,564	43,519
Treasury stock, at cost, 588,203 shares and 159,301 shares at June 30, 2018 and December 31, 2017	(11,606)	(735)
Total stockholders' equity	5,360,221	4,712,295
Noncontrolling interest	739,926	1,168,411
Total equity	6,100,147	5,880,706
TOTAL LIABILITIES AND EQUITY	$9,139,443	$8,793,198

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,	
	2018	2017	2018	2017
	(In thousands, except per share data)			
REVENUES				
Oil sales	$396,325	$178,066	$727,428	$347,811
Natural gas sales	12,235	12,983	29,659	25,450
Natural gas liquids sales	57,275	20,336	97,895	37,749
Other	1,953	2,292	5,547	3,525
Total revenues	467,788	213,677	860,529	414,535
OPERATING EXPENSES				
Lease operating expenses	35,904	29,631	64,736	47,258
Transportation and processing costs	6,471	—	12,738	—
Production and ad valorem taxes	27,331	11,397	51,517	22,559
Depreciation, depletion and amortization	145,552	83,315	266,751	152,285
General and administrative expenses (including stock-based compensation of $5,363 and $5,251 for the three months ended June 30, 2018 and 2017 and $10,432 and $9,460 for the six months ended June 30, 2018 and 2017)	35,991	31,761	70,986	55,803
Exploration and abandonment costs	3,366	2,442	8,777	5,205
Acquisition costs	(2)	7,176	2	8,520
Accretion of asset retirement obligations	359	193	713	329
Other operating expenses	2,477	2,503	4,652	4,786
Total operating expenses	257,449	168,418	480,872	296,745
OPERATING INCOME	210,339	45,259	379,657	117,790
OTHER INCOME (EXPENSE)				
Interest expense, net	(33,758)	(22,764)	(65,726)	(42,100)
Gain on sale of property	5,166	—	5,055	—
Loss on early extinguishment of debt	—	—	—	(3,891)
(Loss) gain on derivatives	(9,466)	43,514	(20,259)	68,130
Change in TRA liability	—	—	(82)	(20,549)
Interest income	1,686	2,178	3,809	4,549
Other income (expense)	234	(177)	535	773
Total other income (expense), net	(36,138)	22,751	(76,668)	6,912
INCOME BEFORE INCOME TAXES	174,201	68,010	302,989	124,702
INCOME TAX EXPENSE	(33,243)	(12,216)	(56,568)	(30,618)
NET INCOME	140,958	55,794	246,421	94,084
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(21,803)	(15,048)	(44,376)	(23,896)
NET INCOME ATTRIBUTABLE TO PARSLEY ENERGY, INC. STOCKHOLDERS	$119,155	$40,746	$202,045	$70,188
Net income per common share:				
Basic	$0.44	$0.17	$0.76	$0.30
Diluted	$0.44	$0.17	$0.76	$0.30

Weighted average common shares outstanding:				
Basic	272,239	245,698	266,479	233,255
Diluted	272,846	246,792	267,043	234,315

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 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	Retained earnings	Treasury stock	Treasury stock	Total stockholders' equity	Noncontrolling interest	Total equi
	(In thousands)										
Balance at December 31, 2017	252,420	62,128	$2,524	$622	$4,666,365	$43,519	159	$(735)	$4,712,295	$1,168,411	$5,880,70
Exchange of PE Units and Class B Common Stock for Class A Common Stock	24,876	(24,876)	249	(249)	472,861	—	—	—	472,861	(472,861)	—
Change in net deferred tax liability due to exchange of PE Units	—	—	—	—	(26,541)	—	—	—	(26,541)	—	(26,541
Issuance of restricted stock	802	—	8	—	(8)	—	—	—	—	—	—
Vesting of restricted stock units	910	—	9	—	(9)	—	—	—	—	—	—
Repurchase of common stock	—	—	—	—	—	—	429	(10,871)	(10,871)	—	(10,871
Restricted stock forfeited	—	—	—	—	(245)	—	—	—	(245)	—	(245
Stock-based compensation	—	—	—	—	10,677	—	—	—	10,677	—	10,677
Conversion of restricted stock units to restricted stock awards	1,098	—	11	—	(11)	—	—	—	—	—	—
Net income	—	—	—	—	—	202,045	—	—	202,045	44,376	246,421
Balance at June 30, 2018	280,106	37,252	$2,801	$373	$5,123,089	$245,564	588	$(11,606)	$5,360,221	$739,926	$6,100,14

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 CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
	2018	2017
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$246,421	$94,084
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	266,751	152,285
Accretion of asset retirement obligations	713	329
Gain on sale of property	(5,055)	—
Loss on early extinguishment of debt	—	3,891
Amortization of deferred loan origination costs	2,374	1,803
Amortization of bond premium	(258)	(258)
Stock-based compensation	10,432	9,460
Deferred income tax expense	56,568	30,476
Change in TRA liability	82	20,549
Loss (gain) on derivatives	20,259	(68,130)
Net cash (paid) received for derivative settlements	(7,211)	2,115
Net cash paid for option premiums	(26,330)	(13,281)
Other	8,208	261
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	(42,993)	(22,575)
Accounts receivable—related parties	147	74
Other current assets	(31,419)	46,318
Other noncurrent assets	(318)	(842)
Accounts payable and accrued expenses	(32,213)	52,672
Revenue and severance taxes payable	24,823	17,973
Net cash provided by operating activities	490,981	327,204
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development of oil and natural gas properties	(854,228)	(361,742)
Acquisitions of oil and natural gas properties	(56,014)	(2,088,286)
Additions to other property and equipment	(48,047)	(19,520)
Proceeds from sales of oil and natural gas properties	42,553	13,557
Maturity of short-term investments	49,627	—
Other	35,018	(630)
Net cash used in investing activities	(831,091)	(2,456,621)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under long-term debt	—	452,480
Payments on long-term debt	(1,461)	(67,411)
Debt issuance costs	(45)	(9,206)
Proceeds from issuance of common stock, net	—	2,123,527
Repurchase of common stock	(10,871)	(137)
Net cash (used in) provided by financing activities	(12,377)	2,499,253
Net (decrease) increase in cash, cash equivalents and restricted cash	(352,487)	369,836
Cash, cash equivalents and restricted cash at beginning of period	554,189	136,669

Cash, cash equivalents and restricted cash at end of period	$201,702	$506,505
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for interest	$64,047	$15,102
Cash paid for income taxes	$—	$200
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:		
Asset retirement obligations incurred, including changes in estimate	$940	$8,084
Additions to oil and natural gas properties - change in capital accruals	$46,969	$121,663
Additions to other property and equipment funded by capital lease borrowings	$1,175	$2,500
Common stock issued for oil and natural gas properties	$—	$1,183,501
Net premiums on options that settled during the period	$(34,598)	$(9,917)

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

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 in December 2013 to succeed the Company's predecessor, which began operations in August 2008 when it acquired operator rights to wells producing from the Spraberry Trend in the Midland Basin. The Company is engaged in the acquisition and development of unconventional oil, natural gas and NGLs reserves located in the Permian Basin, which is located in West Texas and Southeastern New Mexico and is comprised of three primary sub-areas: the Midland Basin, the Central Basin Platform and the Delaware Basin.

NOTE 2. SUMMARY OF ACCOUNTING POLICIES

These condensed consolidated financial statements include the accounts of (i) the Company, (ii) Parsley Energy, LLC, the Company's majority owned subsidiary ("Parsley LLC"), (iii) the direct and indirect wholly owned subsidiaries of Parsley LLC, and (iv) Pacesetter Drilling, LLC, an indirect, majority owned subsidiary of Parsley LLC, of which Parsley LLC owns, indirectly, a 63.0% interest. Parsley LLC also owns, indirectly, 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 omitted from this Quarterly Report, as permitted by SEC rules and regulations. The Company believes the disclosures made in this Quarterly Report are adequate to make the information herein not misleading. The Company recommends that these condensed consolidated financial statements should be read in conjunction with its audited consolidated financial statements and related notes thereto included in the Annual Report.

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, 2018 are not necessarily indicative of the operating results of the entire fiscal year ending December 31, 2018.

Use of Estimates

These condensed consolidated financial statements and related notes are presented in accordance with GAAP. Preparation in accordance with GAAP requires the Company to (i) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board ("FASB") and by the SEC and (ii) 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. The major estimates and assumptions impacting the Company's 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 the Company owns, particularly properties that the Company has 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.

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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.
Reclassifications
Certain reclassifications have been made to prior period amounts to conform to the current presentation. Such reclassifications had no effect on the Company’s previously reported net income, earnings per share, cash flows or retained earnings.
Recent Accounting Pronouncements
Recently Adopted Accounting Pronouncements
In May 2014, the FASB issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Accounting Standards Codification (“ASC”) Topic 605, Revenue Recognition, and most industry-specific guidance. The Company adopted this standard effective January 1, 2018 using the modified retrospective approach. As a result, the Company changed its accounting policy for revenue recognition, as detailed below under “Impact of ASC Topic 606 Adoption.” The Company also implemented processes and controls to ensure new contracts are reviewed for the appropriate accounting treatment and to generate the required disclosures under the standards.
In January 2016, the FASB issued ASU 2016-01, Financial Instruments—Overall, as an amendment to ASC Subtopic 825-10. The amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Among other items, this update will simplify the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. When a qualitative assessment indicates that impairment exists, an entity is required to measure the investment at fair value. This impairment assessment reduces the complexity of the other-than-temporary impairment guidance that certain entities follow. The Company adopted ASU 2016-01 as of January 1, 2018. The adoption of this guidance did not have a material effect on the Company's financial position, results of operation or cash flows.
In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230), which requires that a statement of cash flows explain the total change during the period in cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. The amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statements of cash flows. The amended guidance will be effective for the Company for annual periods beginning after December 15, 2017. The amendments should be applied using a retrospective transition method to each period presented. Early adoption is permitted for any entity in any interim or annual period. The Company implemented the new guidance on January 1, 2018 and disclosure revisions have been made for the periods presented on the condensed consolidated statements of cash flows. The Company’s condensed consolidated statements of cash flows for the six months ended June 30, 2017 were adjusted to conform to this guidance, which resulted in an increase in cash flows from operating activities of $0.6 million.
In March 2018, the FASB issued ASU 2018-05, Income Taxes (Topic 740), which amends certain guidance in ASC 740, Income Taxes, to reflect Staff Accounting Bulletin No. 118, which provides guidance for companies that are not able to complete their accounting for the income tax effects of the Tax Cuts and Jobs Act (the “Tax Act”) in the period of enactment. This guidance also includes amendments to the XBRL Taxonomy. For public business entities, the amendments in ASU 2018-05 are effective for fiscal years ending after December 15, 2020. Early adoption is permitted. The Company has prepared its condensed consolidated financial statements for the three and six months ended June 30, 2018 in accordance with ASU 2018-05. The Company expects to have all estimates finalized by fourth quarter of 2018. Any adjustments recorded to these estimates through 2018 will be included in income from operations as an adjustment to tax expense. The ultimate impact of the Tax Act may differ from the Company’s estimates based on the Company’s further analysis of the new law and additional regulatory guidance that may be issued.

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Recently Issued but Not Yet Adopted Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which modifies lessees' recognition of lease assets and lease liabilities for those leases classified as operating leases under previous GAAP guidance. In July 2018, the FASB issued also ASU No. 2018-10, Codification Improvements to Topic 842, Leases, which further clarifies guidance previously issued. 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 February 2018, the FASB issued ASU No. 2018-03, Technical Corrections and Improvements to Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. This amendment clarifies certain aspects of the new guidance (ASU 2016-01) on recognizing and measuring financial instruments and presentation requirements for certain fair value option liabilities. For public business entities, the amendments in ASU 2018-03 are effective for fiscal years ending after December 15, 2018. Early adoption is permitted. The Company is currently evaluating the effects the adoption of ASU 2018-03 will have on its condensed consolidated financial statements.

In June 2018, the FASB issued ASU No. 2018-07, Compensation—Stock Compensation (Topic 718), which is part of FASB's simplification initiative. The areas for simplification involve multiple aspects of the accounting for non-employee share-based payment transactions and share-based payment transactions for acquiring goods and services from non-employees. For public business entities, the amendments in ASU 2018-05 are effective for fiscal years ending after December 15, 2018. Early adoption is permitted. The Company does not expect adoption of this guidance to have a significant impact on its condensed consolidated financial statements.

Impact of ASC Topic 606 Adoption

The Company's adoption of ASC Topic 606, Revenue from Contracts with Customers ("ASC 606"), resulted in the following adjustments for the three months ended June 30, 2018 (in thousands):

	Three Months Ended June 30, 2018		
	ASC 605	Adjustment	ASC 606
Revenues			
Oil sales	$396,325	$ —	$396,325
Natural gas sales (1)	11,094	1,141	12,235
Natural gas liquids sales (1)	51,945	5,330	57,275
Total production revenues	459,364	6,471	465,835
Operating expenses			
Transportation and processing costs	—	6,471	6,471
Production revenues less transportation and processing costs	$459,364	$ —	$459,364
Net income attributable to Parsley, Inc. stockholders	$119,155	$ —	$119,155

(1) Revenues associated with natural gas and NGLs sales at the plant inlet are considered a single combined performance obligation. The applicable line items include $3.9 million and $16.3 million of natural gas and NGLs sales, respectively, completed at the plant inlet.

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The Company's adoption of ASC 606, resulted in the following adjustments for the six months ended June 30, 2018 (in thousands):

	Six Months Ended June 30, 2018		
	ASC 605	Adjustment	ASC 606
Revenues			
Oil sales	$727,428	$ —	$727,428
Natural gas sales [1]	26,680	2,979	29,659
Natural gas liquids sales [1]	88,136	9,759	97,895
Total production revenues	842,244	12,738	854,982
Operating expenses			
Transportation and processing costs	—	12,738	12,738
Production revenues less transportation and processing costs	$842,244	$ —	$842,244
Net income attributable to Parsley, Inc. stockholders	$202,045	$ —	$202,045

(1) Revenues associated with natural gas and NGLs sales at the plant inlet are considered a single combined performance obligation. The applicable line items include $8.6 million and $26.8 million of natural gas and NGLs sales, respectively, completed at the plant inlet.

Changes to natural gas and NGLs sales were made in accordance with the new control model defined in ASC 606. Under the new control model, the Company was required to identify and separately analyze each contract associated with revenues to determine the appropriate accounting application. The Company considered various indicators for contracts and the weighting of their relevance to determine when control transferred to the customer (such as whether raw gas is sold at the receipt point or residue gas and NGLs are sold at the tailgate of the gas processing plants). Based on this analysis, the Company concluded that the presence of product redelivery and take-in-kind rights, if substantive, are determinative indicators of control transferring at the tailgate if there is intent at contract inception. Additionally, the Company considers risk of loss an important indicator of when control transfers, which is comprised of risks associated with loss of product, exposure to product mix and recoveries, and exposure to index prices versus actual prices. The Company concluded that title, custody, and acceptance are not determinative indicators of control, as such factors may be present in the case of a sale or the performance of a service.

As a result of this analysis, the Company modified its accounting and presentation of natural gas and NGLs sales, and transportation and processing costs under certain marketing agreements. This is due to the conclusion that the Company represents the principal and the ultimate third party is its customer, which implies that the Company maintains control of the product through the tailgate of gas processing plants in certain natural gas processing and marketing agreements with certain midstream entities in accordance with the control model in ASC 606. This is a change from previous conclusions reached by the Company for these agreements, when utilizing the principal versus agent indicators under ASC Topic 605, Revenue Recognition ("ASC 605"), where the Company acted as the agent and the midstream processing entity acted as its customer. As a result, the Company modified its presentation of revenues and expenses for these agreements. Revenues related to these agreements are now presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Transportation and processing costs related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are now presented as Transportation and processing costs on the Company's condensed consolidated statements of operations.

Certain of the Company's contracts for the sale of commodities contain embedded derivatives. The Company has elected to utilize the normal purchases and normal sales scope exception as provided by ASC 815, Derivatives and Hedging.

Revenue from Contracts with Customers

Revenue is measured based on considerations specified in contracts with customers, excluding any sales incentives or amounts collected on behalf of third parties. The Company recognizes revenue when a performance obligation is satisfied by the transfer of control over a product to the ultimate customer. Sales of oil, natural gas and NGLs are recognized at the time that control of the product is transferred to the customer and collectability is reasonably assured. Generally, the pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the prices of the Company's oil, natural gas, and NGLs fluctuate to remain competitive with other available oil, natural gas, and NGLs supplies. The Company reports revenues disaggregated by product on its condensed consolidated statements of operations.

Oil Sales

Oil production is sold at the wellhead and the Company collects an agreed-upon index price, net of pricing differentials. In this scenario, revenue is recognized when control transfers to the purchaser at the wellhead at the net price received by the Company.

Natural Gas and NGLs Sales

Under the Company's natural gas processing contracts, it delivers natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting natural gas and NGLs sales. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction, which includes considerations of product redelivery, take-in-kind rights and risk of loss. For those contracts where the Company has concluded that control of the product transfers at the tailgate of the plant, meaning that the Company is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with transportation and processing fees presented as Transportation and processing costs on the Company's condensed consolidated statements of operations. Alternatively, for those contracts where the Company has concluded control of the product transfers at the inlet of the plant, meaning that the Company is the agent and the midstream processing entity is the Company's customer, the Company recognizes natural gas and NGLs sales based on the net amount of proceeds received from the midstream processing. The Company also determined that losses associated with shrinkage and line loss ("FL&U") occur prior to the change in control. As a result, natural gas and NGLs sales are presented net of FL&U costs.

Production Imbalances

Previously, the Company elected to utilize the entitlements method, which is no longer applicable, to account for natural gas production imbalances. The Company now utilizes the sales method to account for natural gas production imbalances; if the Company sells natural gas to a customer in excess of its entitled share of production, the Company is required perform a principal versus agent analysis to determine whether it should record the gross amount of revenue and transportation and processing costs equal to the other owners' interests or recognize the net amount of revenue. In conjunction with the adoption of ASC 606, for the three and six months ended June 30, 2018, there was no material impact to the financial statements due to this change in accounting for production imbalances.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature, with a contract term of one year or less. For these contracts, the Company has utilized the practical expedient in ASC 606-10-50-14, which exempts the Company from the requirements to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14(a), which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each unit of product generally represents a separate performance obligation   therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract Balances

Under the Company's product sales contracts, the Company invoices customers once performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606.

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Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements for certain natural gas and NGLs sales, however, may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. In these situations, the Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between the Company's revenue estimates and actual revenue received have historically been insignificant. For the three and six months ended June 30, 2018 and 2017, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

NOTE 3. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Instruments and Concentration of Risk

Objective and Strategy

The Company enters into multiple types of commodity derivative contracts to (i) reduce the effect of price volatility on the Company's oil and natural gas revenues and (ii) support the Company's annual capital budgeting and expenditure plans.

Oil Production Derivative Activities

The Company's material physical sales contracts governing its oil production are typically correlated with NYMEX WTI oil prices. The Company uses put spread options, three-way collars and two-way collars to manage oil price volatility, and basis swap contracts and rollfactor swap contracts to reduce basis risk between NYMEX WTI prices and the actual index prices at which the oil is sold.

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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, 2018	Year Ending December 31, 2019
Put spreads[1]		
Purchased:		
Puts		
Notional (MBbl)	6,600	8,700
Weighted average strike price	$ 49.67	$ 56.98
Sold:		
Puts		
Notional (MBbl)	(6,600)	(8,700)
Weighted average strike price	$ 39.66	$ 46.98
Three-way collars		
Purchased:		
Puts		
Notional (MBbl)	5,700	3,300
Weighted average strike price	$ 50.00	$ 50.45
Sold:		
Puts		
Notional (MBbl)	(5,700)	(3,300)
Weighted average strike price	$ 40.00	$ 40.45
Calls		
Notional (MBbl)	(5,700)	(3,300)
Weighted average strike price	$ 75.65	$ 80.36
Two-way collars		
Purchased:		
Puts		
Notional (MBbl)	552	—
Weighted average strike price	$ 45.67	$ —
Sold:		
Calls		
Notional (MBbl)	(552)	—
Weighted average strike price	$ 61.31	$ —
Basis swap contracts [2]		
Midland-Cushing index swap volume (MBbl)	2,084	—
Swap price ($/Bbl)	$ (0.86)	$ —
Rollfactor swap contracts [3]		
Midland-Cushing index swap volume (MBbl)	2,760	—

Swap price ($/Bbl)	$ 0.60	—

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(1) Excludes 2,444 notional MBbls with a fair value of $11.1 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.
(3) These positions hedge the timing risk associated with the Company's physical sales. The Company generally sells crude oil for the delivery month at a sales price based on the average NYMEX price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is the first month.

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 and commodity swap contracts 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 period indicated and the weighted average natural gas prices for those contracts:

Natural Gas	Six Months Ending December 31, 2018
Three-way collars	
Purchased:	
Puts	
Notional (MMbtu)	1,500,000
Weighted average strike price	$ 3.00
Sold:	
Calls	
Notional (MMbtu)	(1,500,000)
Weighted average strike price	$ 2.75
Puts	
Notional (MMbtu)	(1,500,000)
Weighted Average Strike Price	$ 3.60

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 table below summarizes the Company's gains (losses) on derivative instruments for the three and six months ended June 30, 2018 and 2017 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Changes in fair value of derivative instruments	$(2,447)	38,541	$(10,367)	63,458
Net derivative settlements	(7,019)	4,973	(9,892)	4,672
(Loss) gain on derivatives	$(9,466)	$43,514	$(20,259)	$68,130
Net premiums on options that settled during the period [1]	$(18,072)	$(5,063)	$(34,598)	$(9,917)

(1)

The net premium on options that settled during the period represents the cumulative cost of premiums paid and received on positions purchased and sold, which expired during the current period.

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 fair value of the derivative instruments is discussed in Note 14—Disclosures about Fair Value of Financial Instruments. 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, 2018 and 2017, 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 option premiums payable and receivable as of the reporting dates indicated (in thousands):

	Gross Amount	Netting Adjustments	Net Exposure
June 30, 2018			
Derivative assets with right of offset or master netting agreements	$84,698	$(11,081)	$73,617
Derivative liabilities with right of offset or master netting agreements	(114,259)	11,081	(103,178)
December 31, 2017			
Derivative assets with right of offset or master netting agreements	$59,132	$(1,443)	$57,689
Derivative liabilities with right of offset or master netting agreements	(106,986)	1,443	(105,543)

Concentration of Credit Risk
The Company believes that it has limited credit risk with respect to its exchange-traded contracts, as such contracts are subject to financial safeguards and transaction guarantees through NYMEX. Over-the-counter traded options expose the Company to counterparty credit risk. These over-the-counter options are entered into with large multinational financial institutions with investment grade credit ratings or through brokers that require all the transaction parties to collateralize their open option positions. The gross and net credit exposure from the Company's commodity derivative contracts as of June 30, 2018 and December 31, 2017 is summarized in the preceding table.
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 typically enters into International Swap Dealers Association Master Agreements ("ISDA Agreements") with 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. If the Company believes a counterparty's creditworthiness has declined or is suspect, it may seek to novate the applicable ISDA Agreement to another financial institution that has an ISDA Agreement in place with the Company. The Company did not incur any losses due to counterparty nonperformance during the three and six months ended June 30, 2018 or the year ended December 31, 2017.

Credit Risk Related Contingent Features in Derivatives

Certain commodity derivative instruments contain provisions that require the Company to either post additional collateral or collateral support (including letters of credit, security interests in an asset, or a performance bond or guarantee), or immediately settle any outstanding liability balances, upon the occurrence of a specified credit risk related event. These events, which are set forth in the Company's existing commodity derivative contracts, include, among others, downgrades in the credit ratings of the Company and its affiliates, events of default under the Company's revolving credit agreement (the "Revolving Credit Agreement"), and the release of collateral (other than as provided under the terms of the Company's Revolving Credit Agreement). Although the Company could be required to post additional collateral or collateral support, or immediately settle any outstanding liability balances, under such conditions, the Company seeks to reduce its potential risk by entering into commodity derivative contracts with several different counterparties.

NOTE 4. PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2018	December 31, 2017
Oil and natural gas properties:		
Subject to depletion	$5,543,512	$4,492,802
Not subject to depletion		
Incurred in 2018	546,240	—
Incurred in 2017	2,271,009	2,837,766
Incurred in 2016 and prior	1,073,809	1,220,746
Total not subject to depletion	3,891,058	4,058,512
Oil and natural gas properties, successful efforts method	9,434,570	8,551,314
Less accumulated depreciation, depletion and impairment	(1,074,499)	(822,459)
Total oil and natural gas properties, net	8,360,071	7,728,855
Other property, plant and equipment	177,952	131,115
Less accumulated depreciation	(31,435)	(24,528)
Other property, plant and equipment, net	146,517	106,587
Total property, plant and equipment, net	$8,506,588	$7,835,442

Costs subject to depletion are proved costs and costs not subject to depletion are unproved costs and current drilling projects.

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 $141.9 million and $259.5 million for the three and six months ended June 30, 2018, respectively, and $80.4 million and $147.1 million for the three and six months ended June 30, 2017, respectively. The Company had no exploratory wells in progress at June 30, 2018 or December 31, 2017.

NOTE 5. ACQUISITIONS AND DIVESTITURES

Acquisitions

During the three and six months ended June 30, 2018, the Company incurred costs of $28.6 million and $56.0 million, respectively, related to the purchase of leasehold acreage. During the three and six months ended June 30, 2018, the Company reflected $27.0 million and $50.9 million, respectively, as part of costs not subject to depletion and $1.6 million and $5.1 million, respectively, as part of costs subject to depletion within its oil and natural gas properties.

On April 20, 2017, the Company and Parsley LLC completed the acquisition (the "Double Eagle Acquisition") of all of the interests in Double Eagle Lone Star LLC, DE Operating LLC, and Veritas Energy Partners, LLC (which were subsequently renamed Parsley DE Lone Star LLC, Parsley DE Operating LLC, and Parsley Veritas Energy Partners, LLC, respectively) from Double Eagle Energy Permian Operating LLC ("DE Operating"), Double Eagle Energy Permian LLC ("DE Permian"), and Double Eagle Energy Permian Member LLC (together with DE Operating and DE Permian, "Double Eagle"), as well as certain related transactions with an affiliate of Double Eagle. The aggregate consideration for the Double Eagle Acquisition, following post-closing adjustments, was $2,579.1 million, which consisted of (i) approximately $1,395.6 million in cash and (ii) 39,848,518 units of PE Units and a corresponding 39,848,518 shares of the Company's Class B common stock, par value $0.01 per share ("Class B Common Stock"). Of the aggregate consideration transferred, approximately $172.3 million in cash and 4,921,557 PE Units (and a corresponding 4,921,557 shares of Class B Common Stock) were deposited in an indemnity holdback escrow account. On April 16, 2018, approximately $138.4 million and 3,937,246 PE Units (and a corresponding 3,937,246 shares of Class B Common Stock) were released from the indemnity holdback escrow account.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed as a result of the Double Eagle Acquisition (in thousands):

Cash	$2,469
Receivables	20,756
Derivatives	3,970
Proved oil and natural gas properties	353,000
Unproved oil and natural gas properties	2,257,266
Total assets acquired	2,637,461
Accounts payable	(48,179)
Deferred tax liability	(10,167)
Total liabilities assumed	(58,346)
Estimated fair value of net assets acquired	$2,579,115

The Company has included in its condensed consolidated statements of operations revenues of $21.4 million and $55.0 million and earnings of $15.7 million and $45.0 million for the three and six months ended June 30, 2018, respectively, associated with the Double Eagle Acquisition. The Company included in its condensed consolidated statements of operations revenues of $21.2 million and earnings of $18.1 million for the period from April 20, 2017 to June 30, 2017 due to the Double Eagle Acquisition.

During the three and six months ended June 30, 2018 and June 30, 2017, the Company exchanged certain unproved acreage and oil and natural gas properties with third parties, with no gain or loss recognized.

Divestitures

During the three months ended June 30, 2018, the Company closed the sale of certain surface and mineral acreage for proceeds of $34.4 million, subject to customary purchase price adjustments, which is considered a receivable as of June 30, 2018 and is included in other current assets on the Company's consolidated balance sheets and as other investing activities on the Company's consolidated statements of cash flows. The Company recognized a $5.2 million gain on the sale.

During the six months ended June 30, 2018, the Company also closed sales of certain leasehold acreage for proceeds of $42.6 million, including customary purchase price adjustments. Upon closing these sales, the Company recognized no gain or loss in accordance with the guidance for partial sales of oil and natural gas properties under ASC Topic 932, Extractive Activities—Oil and Gas.

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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, 2018 (in thousands):

	June 30, 2018
Asset retirement obligations, beginning of period	$27,170
Additional liabilities incurred	1,083
Accretion expense	713
Liabilities settled upon plugging and abandoning wells	(143)
Disposition of wells	(216)
Asset retirement obligations, end of period	$28,607

NOTE 7. DEBT
The Company's debt consisted of the following as of the dates indicated (in thousands):

	June 30, 2018	December 31, 2017
Revolving Credit Agreement	$—	$—
6.250% senior unsecured notes due 2024	400,000	400,000
5.375% senior unsecured notes due 2025	650,000	650,000
5.250% senior unsecured notes due 2025	450,000	450,000
5.625% senior unsecured notes due 2027	700,000	700,000
Capital leases	4,620	4,906
Total debt	2,204,620	2,204,906
Debt issuance costs on senior unsecured notes	(24,653)	(26,341)
Premium on senior unsecured notes	3,054	3,312
Less: current portion	(2,462)	(2,352)
Total long-term debt	$2,180,559	$2,179,525

Revolving Credit Agreement
On April 30, 2018, the Company, Parsley LLC, each of the guarantors thereto, Wells Fargo Bank, National Association, as administrative agent, and the other lenders party thereto entered into the Sixth Amendment (the "Sixth Amendment") to the Revolving Credit Agreement. The Sixth Amendment, among other things, modified the terms of the Revolving Credit Agreement to (i) increase the borrowing base under the Revolving Credit Agreement from $1.8 billion to $2.3 billion (although the aggregate elected commitments under the Revolving Credit Agreement remained at $1.0 billion), (ii) decrease the applicable margins for borrowings under the Revolving Credit Agreement to a range of (A) 1.25% to 2.25% for LIBOR based borrowings and (B) 0.25% to 1.25% for alternative base rate based borrowings, with the specific applicable margins determined by reference to borrowing base utilization, (iii) reduce the frequency of scheduled borrowing base redeterminations from semi-annually to annually in certain circumstances, (iv) remove the cap on the amount of additional indebtedness allowed in the form of unsecured senior notes, (v) provide additional flexibility, subject to certain conditions, to make restricted payments, (vi) provide enhanced flexibility, subject to certain dollar limitations, to make investments in unrestricted subsidiaries and joint ventures and to make other investments, (vii) permit, subject to certain conditions, the dispositions of equity interests in unrestricted subsidiaries and (viii) amend certain other negative covenants.

As of June 30, 2018, the borrowing base under the Revolving Credit Agreement was $2.3 billion, with a commitment level of $1.0 billion. There were no borrowings outstanding and $8.8 million in letters of credit outstanding as of June 30, 2018, resulting in availability of $991.3 million. The amount Parsley LLC is able to borrow under the Revolving Credit Agreement is

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subject to compliance with the financial covenants, satisfaction of various conditions precedent to borrowing and other provisions of the Revolving Credit Agreement.

As of June 30, 2018, letters of credit under the Revolving Credit Agreement bear a 1.25% weighted average interest rate.

Covenant Compliance

The Revolving Credit Agreement and the indentures governing the 5.625% senior unsecured notes due 2027 (the “2027 Notes”), 5.250% senior unsecured notes due 2025 (the “New 2025 Notes”), the 5.375% senior unsecured notes due 2025 (the “2025 Notes”), and the 6.250% senior unsecured notes due 2024 (the “2024 Notes” and, together with the 2027 Notes, the New 2025 Notes and the 2025 Notes, the “Notes”) restrict the Company’s ability and the ability of certain of its 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 its capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make investments; (v) create certain liens; (vi) enter into agreements that restrict its restricted subsidiaries from issuing dividends or making other payments to the Company; (vii) consolidate, merge or transfer all or substantially all of its 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 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 indentures) 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 subsequently decline to below investment grade, the suspended covenants would be reinstated.

As of June 30, 2018, the Company was in compliance with all required covenants under the Revolving Credit Agreement and each of the indentures governing the Notes.

Principal Maturities of Debt

Principal maturities of debt outstanding at June 30, 2018 are as follows (in thousands):

2018	$1,253
2019	2,229
2020	949
2021	160
2022	26
Thereafter	2,200,003
Total	$2,204,620

Interest Expense

The following amounts have been incurred and charged to interest expense for the three and six months ended June 30, 2018 and 2017 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Cash payments for interest	$34,592	$12,639	$64,047	$15,102
Change in interest accrual	(1,890)	9,234	(437)	25,453
Amortization of deferred loan origination costs	1,185	1,020	2,374	1,803
Amortization of bond premium	(129)	(129)	(258)	(258)
Total interest expense, net	$33,758	$22,764	$65,726	$42,100

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 exchanges of outstanding PE Units (and corresponding shares of its outstanding Class B Common Stock), and the treasury stock method to determine the potential dilutive effect of vesting of its outstanding restricted stock and restricted stock units. For the three and six months ended June 30, 2018 and 2017, Class B Common Stock was not recognized in dilutive earnings per share calculations as the effect would have been antidilutive.

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,	
	2018	2017	2018	2017
Basic EPS (in thousands, except per share data)				
Numerator:				
Basic net income attributable to Parsley Energy, Inc. Stockholders	$119,155	$40,746	$202,045	$70,188
Denominator:				
Basic weighted average shares outstanding	272,239	245,698	266,479	233,255
Basic EPS attributable to Parsley Energy, Inc. Stockholders	$0.44	$0.17	$0.76	$0.30
Diluted EPS				
Numerator:				
Net income attributable to Parsley Energy, Inc. Stockholders	119,155	40,746	202,045	70,188
Diluted net income attributable to Parsley Energy, Inc. Stockholders	$119,155	$40,746	$202,045	$70,188
Denominator:				
Basic weighted average shares outstanding	272,239	245,698	266,479	233,255
Effect of dilutive securities:				
Time-Based Restricted Stock and Time-Based Restricted Stock Units	607	1,094	564	1,060
Diluted weighted average shares outstanding (1)	272,846	246,792	267,043	234,315
Diluted EPS attributable to Parsley Energy, Inc. Stockholders	$0.44	$0.17	$0.76	$0.30

(1) As of June 30, 2018 and 2017, there were 1,356,522 shares of performance-based restricted stock ("PSAs") and 640,062 performance-based restricted stock units ("PSUs"), respectively, that could vest 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, 2018 and 2017, 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 equity offerings completed by the Company in 2017, the consummation of the Double Eagle Acquisition and exchanges by holders of PE Units (the "PE Unit Holders"), during 2017, the Company's ownership of Parsley LLC decreased from 86.5% to 80.2% and the PE Unit Holders' ownership of Parsley LLC increased from 13.5% to 19.8%.

During the six months ended June 30, 2018, certain PE Unit Holders exercised their exchange right under the Second Amended and Restated Limited Liability Company Agreement of Parsley LLC (the "Parsley LLC Agreement"), collectively electing to exchange an aggregate of 24,876,519 PE Units (and a corresponding number of shares of Class B Common Stock) for an aggregate of 24,876,519 shares of the Company's Class A common stock, par value $0.01

per share (“Class A Common Stock”). In turn, the Company exercised its call right under the Parsley LLC Agreement, electing to issue Class A Common

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Stock directly to each of the exchanging PE Unit Holders in satisfaction of their election notices. As a result of these exchanges of PE Units (and corresponding shares of Class B Common Stock) for shares of Class A Common Stock during the six months ended June 30, 2018, the Company's ownership in Parsley LLC increased from 80.2% to 88.2% and the ownership of the PE Unit Holders in Parsley LLC decreased from 19.8% to 11.8%.
Because these changes in the Company's ownership interest in Parsley LLC did not result in a change of control, the transactions were accounted for as equity transactions under ASC Topic 810, Consolidation, which requires that any differences between the carrying value of the Company's basis in Parsley LLC and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest.
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.
The following table summarizes the noncontrolling interest income (loss):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands)			
Net income (loss) attributable to the noncontrolling interests of:				
Parsley LLC	$21,704	$14,950	$44,119	$23,957
Pacesetter Drilling, LLC	99	98	257	(61)
Total net income attributable to noncontrolling interest	$21,803	$15,048	$44,376	$23,896

NOTE 9. STOCK-BASED COMPENSATION
In connection with the Company's initial public offering (the "IPO"), 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—Incentive Compensation" in the Company's Proxy Statement filed on Schedule 14A for the 2018 Annual Meeting of Stockholders for additional information related to this equity based compensation plan.
On February 12, 2018, the PSUs granted in 2016 and 2017 were converted into PSAs at 200% of the target payout for such awards. Similarly, certain of the time-based restricted stock units ("RSUs") granted in 2016 were also converted to time-based restricted stock awards ("RSAs") on February 12, 2018. As converted, the PSAs and RSAs are intended to be economically identical to the pre-conversion awards with the same material terms and conditions, including vesting schedules and performance criteria.
Stock-based compensation expense recorded for each type of stock-based compensation award for the three and six months ended June 30, 2018 and 2017 is as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Time-based restricted stock	$2,166	$1,491	$4,054	$2,608
Time-based restricted stock units	1,377	2,087	3,032	3,878
Performance-based restricted stock awards (1)	1,820	1,673	3,346	2,974
Total stock-based compensation	$5,363	$5,251	$10,432	$9,460

(1) Includes stock based compensation expense related to historical performance-based stock units.
Stock-based compensation is included in General and administrative expenses in the Company's condensed consolidated statements of operations included within this Quarterly Report. There was approximately $33.1 million of unamortized compensation expense relating to outstanding RSAs, RSUs, and PSAs at June 30, 2018. The unrecognized compensation

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expense will be recognized on a straight-line basis over the remaining vesting periods of the awards, which is a period of less than three years on a weighted average basis.

The following table summarizes the Company's time-based restricted stock, time-based restricted stock unit, and performance-based restricted stock award activity for the six months ended June 30, 2018 (in thousands):

	Time-Based Restricted Stock (RSAs)	Time-Based Restricted Stock Units (RSUs)	Performance-Based Restricted Stock Units (PSUs)	Performance-Based Restricted Stock Awards (PSAs)
Outstanding at January 1, 2018	779	1,200	640	—
Granted [(1)]	302	279	—	500
Converted	242	(242)	(428)	856
Vested	(593)	(486)	(212)	—
Forfeited	—	(32)	—	—
Outstanding at June 30, 2018	730	719	—	1,356
(1) Weighted average grant date fair value	$ 27.91	$ 27.37	$ —	$ 13.72

NOTE 10. INCOME TAXES

The Company is a corporation and is subject to U.S. federal income tax and the Texas Margins Tax. On December 22, 2017, Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act, was enacted by the U.S. government. The Tax Act significantly impacted the Company's 2017 effective tax rate and made broad and complex changes to the U.S. corporate income tax code. Among other changes, the Tax Act: (i) reduced the U.S. federal corporate income tax rate from 35% to 21%; (ii) repealed the corporate alternative minimum tax and provides for a refund of previously accrued alternative minimum tax credits; (iii) modified the provisions relating to the limitations on deductions for executive compensation of publicly traded corporations; (iv) enacted new limitations regarding the deductibility of interest expense; and (v) imposed new limitations on the utilization of net operating losses arising in taxable years beginning after December 31, 2017.

GAAP requires that the impact of tax legislation be recognized in the period in which the law was enacted. As a result of the Tax Act, the Company remeasured its deferred tax assets and liabilities based on the federal income and state income tax rates at which they are now expected to reverse, and they now generally reflect a federal income tax rate of 21%. Any adjustments recorded to these estimates through 2018 will be included in income from operations as an adjustment to tax expense. The ultimate impact of the Tax Act may differ from the Company's estimates based on the Company's further analysis of the new law and additional regulatory guidance that may be issued. Further, the amount of the Company's future federal income tax will be dependent upon its future taxable income.

The Company's effective combined U.S. federal and state income tax rate for the six months ended June 30, 2018 and 2017 was 18.7% and 24.6%, respectively. During the three and six months ended June 30, 2018, the Company recognized an income tax expense of $33.2 million and $56.6 million, respectively. During the three and six months ended June 30, 2017, the Company recognized an income tax expense of $12.2 million and $30.6 million, respectively. Total income tax expense for the three and six months ended June 30, 2018 differed from amounts computed by applying the U.S. federal statutory tax rate of 21% due primarily to the impact of net income attributable to noncontrolling ownership interests as well as the impact of state income taxes and the reversal of a portion of the valuation allowance recorded in 2017.

The net effect of the exchange of PE Units and Class B Common Stock for Class A Common Stock during the six months ended June 30, 2018 was an increase of deferred tax liability of $22.4 million.

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 PE Unit Holders prior to the IPO (each such person, a “TRA Holder”), including certain executive officers. The TRA 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 or, if either the Company or Parsley LLC so elects, cash, 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 hypothetical future tax benefits that could be paid under 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.

The actual amount and timing of payments to be made under the TRA will depend on a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the use of loss carryovers and the portion of the Company’s payments under the TRA constituting imputed interest. As of June 30, 2018, there have been no payments associated with the TRA.

As a result of the exchange of PE Units by certain TRA Holders, the Company recorded additional deferred tax assets of $4.9 million during the six months ended June 30, 2018. The payable pursuant to the TRA was also increased by $4.1 million, which is 85% of the deferred tax asset and additional paid in capital was increased by $0.7 million.

As of June 30, 2018 and December 31, 2017, the Company had recorded a TRA liability of $62.7 million and $58.5 million, respectively, for the estimated payments that will be made to the TRA Holders who have exchanged shares along with corresponding deferred assets, net of valuation allowance, of $73.7 million and $68.8 million, respectively, as a result of the increase in tax basis arising from such exchanges and the decrease in tax basis as a result of the decrease in the future statutory tax rate.

NOTE 11. COMMITMENTS AND CONTINGENCIES

Legal Matters

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

Environmental Obligations

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

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

Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At both June 30, 2018 and December 31, 2017, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

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Contractual Obligations
The Company had no material changes in its contractual commitments and obligations from amounts listed under Note 12—Commitments and Contingencies in its Annual Report on Form 10-K for the year ended December 31, 2017.
NOTE 12. RELATED PARTY TRANSACTIONS
Well Operations
During the three and six months ended June 30, 2018 and 2017, certain of the Company's directors, officers, 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 and six months ended June 30, 2018 totaled $0.4 million and $0.9 million, respectively. The revenues disbursed to such Related Party Working Interest Owners for the three and six months ended June 30, 2017 totaled $0.4 million and $0.8 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 discussed in Note 2—Summary of Accounting Policies, the Company owns a 42.5% interest in SPS. The Company accounts for this investment using the equity method. 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 and six months ended June 30, 2018, the Company incurred charges totaling $4.0 million and $8.0 million, respectively, as compared to $3.5 million and $5.6 million, respectively, for the three and six months ended June 30, 2017, 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 and six months ended June 30, 2018, the Company incurred charges totaling $1.1 million and $3.7 million, respectively, for services performed by Lone Star for the Company's well operations and drilling activities. During the three and six months ended June 30, 2017, the Company incurred charges totaling $2.4 million and $5.0 million, respectively, for services performed by Lone Star for the Company's well operations and drilling activities.
Exchange Right
In accordance with the terms of the Parsley LLC Agreement, the PE Unit Holders generally have the right to exchange their PE Units (and a corresponding number of shares of the Class B Common Stock) for shares of 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, if the Company or Parsley LLC so elects, cash. As a PE Unit Holder exchanges its PE Units, the Company's interest in Parsley LLC will be correspondingly increased.
NOTE 13. SIGNIFICANT CUSTOMERS

For the six months ended June 30, 2018 and 2017, each of the following purchasers accounted for more than 10% of the Company's revenue:

	Six Months Ended June 30,	
	2018	2017
Shell Trading (US) Company	54%	67%

Lion Oil, Inc.	21%	—%
Targa Pipeline Mid-Continent, LLC	11%	13%

If a significant customer decided to stop purchasing oil and natural gas from the Company, the Company's revenue could decline and the Company's operating results and financial condition could be harmed. While the Company believes that the Company could procure substitute or additional customers to offset the loss of one or more of the Company's current significant customers, there is no assurance that the Company would be successful in doing so on terms acceptable to the Company or at all.

NOTE 14. 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 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.

The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable (e.g., if there was a sustained decline in commodity prices or the productivity of the Company's wells). The Company reviews its oil and natural gas properties by field. An impairment loss is recognized if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of a particular asset, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of such asset.

Proved oil and natural gas properties. During the three and six months ended June 30, 2018 and 2017, the Company did not recognize impairment charges, as the carrying amount of the assets exceeds the undiscounted future cash flows of the assets.

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 (iv) results of future drilling activities.

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Financial Assets and Liabilities Measured at Fair Value
Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.
The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis (in thousands):

	June 30, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Money market funds	$127,787	$—	$ —	$127,787
Commodity derivative instruments(1)	—	73,617	—	73,617
Total assets	$127,787	$73,617	$ —	$201,404
Liabilities:				
Commodity derivative instruments(1)	$—	$(103,178)	$ —	$(103,178)
Total liabilities	$—	$(103,178)	$ —	$(103,178)
Net asset (liability)	$127,787	$(29,561)	$ —	$98,226

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
Assets:				
Money market funds	$476,619	$—	$ —	$476,619
Commodity derivative instruments(1)	—	57,689	—	57,689
Total assets	$476,619	$57,689	$ —	$534,308
Liabilities:				
Commodity derivative instruments(1)	$—	$(105,543)	$ —	$(105,543)
Total liabilities	$—	$(105,543)	$ —	$(105,543)
Net asset (liability)	$476,619	$(47,854)	$ —	$428,765

(1) Includes deferred premiums to be settled upon expiration of the contract.

Money market funds in the preceding tables consist of money market funds included in cash and cash equivalents on the Company's consolidated balance sheets at June 30, 2018 and December 31, 2017. The Company's money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identifies the money market funds as Level 1 instruments because the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments. During the three and six months ended June 30, 2018, income related to these investments was $1.6 million and $3.5 million, respectively, and is recorded on the Company's condensed consolidated statements of operations as Interest income. During the three and six months ended June 30, 2017, income related to these investments was $2.0 million and $4.4 million, respectively, and is recorded on the Company's condensed consolidated statements of operations as Interest income.
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 because 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.

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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, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents:				
Commercial paper	$ —	$ —	$24,939	$24,918
Short-term investments:				
Commercial paper	99,704	99,674	149,283	149,151
Long-term debt:				
6.250% senior unsecured notes due 2024	400,000	407,252	400,000	423,824
5.375% senior unsecured notes due 2025	650,000	646,536	650,000	658,483
5.250% senior unsecured notes due 2025	450,000	443,520	450,000	454,010
5.625% senior unsecured notes due 2027	700,000	695,429	700,000	715,169
Revolving Credit Agreement	—	—	—	—

The fair values of the Notes were determined using the June 30, 2018 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, 2018, there are no indicators for change in the Company's market spread.

Periodically, the Company invests in commercial paper with investment grade rated entities. The investments are carried at amortized cost and classified as held-to-maturity because the Company has the intent and ability to hold them until they mature. The net carrying value of held-to-maturity investments is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the investments. Income related to these investments is recorded on the Company's condensed consolidated statements of operations as Interest income.

The following tables provide the components of the Company's cash and cash equivalents and short-term investments as of the dates indicated (in thousands):

	June 30, 2018			
Consolidated Balance Sheet Location	Cash	Commercial Paper	Money Market Funds	Total
Cash and cash equivalents	$73,915	$ —	$127,787	$201,702
Short-term investments	—	99,704	—	99,704

	December 31, 2017			
Consolidated Balance Sheet Location	Cash	Commercial Paper	Money Market Funds	Total
Cash and cash equivalents	$52,631	$ 24,939	$476,619	$554,189
Short-term investments	—	149,283	—	149,283

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

NOTE 15. SUBSEQUENT EVENTS

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

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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, 2017 (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 to succeed our predecessor, which began operations in August 2008 when it acquired operator rights to wells producing from the Spraberry Trend in the Midland Basin from Joe Parsley, a co-founder of Parker and Parsley Petroleum Company.

We are an independent oil and natural gas company focused on the acquisition and development of unconventional oil, natural gas and NGLs reserves in the Permian Basin. The Permian Basin is located in West Texas and Southeastern New Mexico and is comprised of three primary sub-areas: the Midland Basin, the Central Basin Platform and the Delaware Basin. These areas are characterized by high oil and liquids-rich natural gas content, multiple vertical and horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates. Our properties are located in the Midland and Delaware Basins, where, given the historical associated returns, we focus predominantly on horizontal development drilling.

As a holding company and the sole managing member of Parsley Energy, LLC ("Parsley LLC"), (i) our sole material asset consists of 279,518,737 PE Units as of June 30, 2018, (ii) we are responsible for all operational, management and administrative decisions of Parsley LLC, and (iii) we consolidate the financial results of Parsley LLC and its subsidiaries.

Our Properties

The following table sets forth information as of June 30, 2018 relating to our leasehold acreage:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
Area	Gross	Net	Gross	Net	Gross	Net
Midland Basin	171,553	121,987	67,366	42,503	238,919	164,490
Delaware Basin	36,245	33,685	14,492	12,030	50,737	45,715
Total	207,798	155,672	81,858	54,533	289,656	210,205

In addition to the leasehold acreage described above, as of June 30, 2018, we held mineral and/or royalty interests in 44,168 gross acres. These mineral rights and associated royalty interests boost our net revenue interest in the applicable properties.

The majority of our identified horizontal drilling locations are located in Upton, Reagan, Midland, Howard, Martin and Glasscock Counties, Texas, in the Midland Basin, and Pecos and Reeves Counties, Texas, in the Delaware Basin.

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As of June 30, 2018, we operated the following wells:

	Vertical Wells		Horizontal Wells		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Midland Basin	1,014	772.1	307	282.7	1,321	1,054.8
Delaware Basin	14	13.5	75	69.8	89	83.3
Total	1,028	785.6	382	352.5	1,410	1,138.1

As of June 30, 2018, we held an interest in 1,830 gross (1,204.4 net) wells, including wells that we do not operate. As of June 30, 2018, we owned an immaterial number of productive wells related to the production of natural gas.

Since commencing our horizontal drilling program in 2013 through June 30, 2018, we have placed on production 282 gross (263.4 net) horizontal wells in the Midland Basin and 56 gross (53.9 net) horizontal wells in the Delaware Basin. The table below summarizes the horizontal wells placed on production during the periods indicated:

	Three Months Ended June 30, 2018		Six Months Ended June 30, 2018	
Area	Gross	Net	Gross	Net
Midland Basin	37	35.9	57	55.0
Delaware Basin	8	7.7	29	28.3
Total	45	43.6	86	83.3

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.

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Sources of Our Revenues

Our production 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, and do not include the effects of derivatives. Our production revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Natural gas and NGLs sales and associated production volumes for the three and six months ended June 30, 2018 reflect adjustments associated with our adoption of ASC Topic 606, Revenue from Contracts with Customers ("ASC 606"), effective January 1, 2018, as discussed in Factors Affecting the Comparability of our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption.

The following table presents the breakdown of our production revenues for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Oil sales	85%	84%	86%	85%
Natural gas sales	3 %	6 %	3 %	6 %
Natural gas liquids sales	12%	10%	11%	9 %

Other revenues are not material and include fees charged by certain of our subsidiaries, Pacesetter Drilling, LLC ("Pacesetter") and Parsley Minerals, LLC, to third parties for drilling services and surface use in the normal course of business. In addition, other revenues include salt water and gathering system income.

Production Volumes

The following table presents historical production volumes for our properties for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Oil (MBbls)	6,165	3,917	11,506	7,311
Natural gas (MMcf)	9,235	5,421	17,791	9,840
Natural gas liquids (MBbls)	2,106	1,069	3,749	1,869
Total (MBoe)	9,811	5,890	18,221	10,821
Average net production (Boe/d)	107,813	64,725	100,669	59,785

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 depends 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 through 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 production revenues are more sensitive to fluctuations in the price of oil than they are to fluctuations in the price of natural gas or NGLs.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, 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.

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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, natural gas or NGLs production. The volumes and terms of our derivative instruments as of June 30, 2018 were as follows:

Description and Production Period	VOLUME (MBbls)	SHORT PUT PRICE ($/Bbl)	LONG PUT PRICE ($/Bbl)	SHORT CALL PRICE ($/Bbl)	PRICE
Crude oil put spreads[1]:					
Jul 2018 - Dec 2018	5,400	$ 40.00	$ 50.00		
Jul 2018 - Dec 2018	900	$ 37.50	$ 47.50		
Oct 2018 - Dec 2018	300	$ 40.00	$ 50.00		
Jan 2019 - Jun 2019	2,100	$ 40.00	$ 50.00		
Jan 2019 - Jun 2019	2,100	$ 50.00	$ 60.00		
Jul 2019 - Dec 2019	1,500	$ 45.00	$ 55.00		
Jul 2019 - Dec 2019	600	$ 47.50	$ 57.50		
Jul 2019 - Dec 2019	900	$ 50.00	$ 60.00		
Jul 2019 - Dec 2019	1,500	$ 52.50	$ 62.50		
Total	15,300				
Crude oil three-way collars[2]:					
Jul 2018 - Dec 2018	1,500	$ 40.00	$ 50.00	$ 76.25	
Jul 2018 - Dec 2018	600	$ 40.00	$ 50.00	$ 76.93	
Jul 2018 - Dec 2018	1,200	$ 40.00	$ 50.00	$ 76.80	
Jul 2018 - Dec 2018	1,200	$ 40.00	$ 50.00	$ 74.75	
Jul 2018 - Dec 2018	1,200	$ 40.00	$ 50.00	$ 74.00	
Jan 2019 - Dec 2019	1,200	$ 40.00	$ 50.00	$ 81.00	
Jan 2019 - Dec 2019	1,800	$ 40.00	$ 50.00	$ 80.00	
Jul 2019 - Dec 2019	300	$ 45.00	$ 55.00	$ 80.00	
Total	9,000				
Crude oil collars[3]:					
Jul 2018 - Dec 2018	184		$ 47.00	$ 59.40	
Jul 2018 - Dec 2018	92		$ 45.00	$ 60.00	
Jul 2018 - Dec 2018	92		$ 45.00	$ 60.85	
Jul 2018 - Dec 2018	184		$ 45.00	$ 64.10	
Total	552				
Crude oil basis swaps[4]:					
Jul 2018 - Dec 2018	180				$ (0.95)
Jul 2018 - Dec 2018	632				$ (1.00)
Jul 2018 - Dec 2018	420				$ (0.85)
Jul 2018 - Dec 2018	300				$ (0.50)
Jul 2018 - Dec 2018	460				$ (0.80)
Jul 2018 - Dec 2018	92				$ (1.30)
Total	2,084				
Rollfactor swap contracts[5]:					
Jul 2018 - Dec 2018	920				$ 0.56

Jul 2018 - Dec 2018	920	$0.60
Jul 2018 - Dec 2018	920	$0.65
Total	2,760	

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Description and Production Period	VOLUME (MMbtu)	SHORT PUT PRICE ($/MMbtu)	LONG PUT PRICE ($/MMbtu)	SHORT CALL PRICE ($/MMbtu)
Natural gas three-way collars(6):				
Jul 2018 - Dec 2018	1,500,000	$ 2.75	$ 3.00	$ 3.60
Total	1,500,000			

(1) When the NYMEX price is above the long put price, we receive the NYMEX price. When the NYMEX price is between the long put price and the short put price, we receive the long put price. When the NYMEX price is below the short put price, we receive the NYMEX price plus the difference between the short put price and the long put price.

(2) Functions similarly to put spreads, except that when the index price is at or

above the call price, we receive the call price.

(3) When the NYMEX price is below the long put price, we receive the long put price. When the NYMEX price is between the put and short call prices, we receive the NYMEX price. When the NYMEX price is above the short call price, we receive the short call price.

(4) We receive or pay the differential price on our crude oil basis swaps.

(5) These swap contracts fix the adjustment at the swap price to ensure that we receive a sales price based on the average NYMEX price during that month, plus an

(6) adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is the first month. Functions similarly to put spreads, except that when the index price is at or above the call price, we receive the call price.

We will have recognized the following cumulative losses in the line item (Loss) gain on derivatives on our condensed consolidated statements of operations from net premiums paid or deferred on options that will settle during the following periods (in thousands):

Q3 2018	(17,854)
Q4 2018	(19,114)
Q1 2019	(9,215)
Q2 2019	(9,215)
Q3 2019	(9,823)
Q4 2019	(9,823)
Total	$ (75,044)

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.

Given the volatility of commodity prices in recent years 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 three and six months ended June 30, 2018 and 2017, we did not recognize an impairment of our proved oil and natural gas properties. At June 30, 2018, in our significant fields that comprise 100% 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 154% per field and, individually, by a minimum of 151%.

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 in the undiscounted future cash flow estimate, except commodity price estimates, remained relatively consistent from June 30, 2017 to June 30, 2018. Future commodity pricing for oil and NGLs is based on five-year WTI futures prices, which increased from June 30, 2017 to June 30, 2018, and future commodity pricing for natural gas is based on five-year Henry Hub futures prices, which decreased from June 30, 2017 to June 30, 2018. In terms of the increase in

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value of undiscounted cash flows from June 30, 2017 to June 30, 2018, the effect of the increase in oil and NGLs prices 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 there could be 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 respect to 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 the Annual Report.
Any decrease in pricing, negative change in price differentials or 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 10% in estimated future pricing of oil and natural gas commodities as of June 30, 2018, however, would not have resulted in an impairment of our proved oil and natural gas properties.

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

Revolving Credit Agreement

On April 30, 2018, the Company, Parsley LLC, each of the guarantors thereto, Wells Fargo Bank, National Association, as administrative agent, and the other lenders party thereto entered into the Sixth Amendment (the "Sixth Amendment") to our revolving credit agreement (the "Revolving Credit Agreement"). The Sixth Amendment, among other things, modified the terms of the Revolving Credit Agreement to (i) increase the borrowing base under the Revolving Credit Agreement from $1.8 billion to $2.3 billion (although the aggregate elected commitments under the Revolving Credit Agreement remained at $1.0 billion), (ii) decrease the applicable margins for borrowings under the Revolving Credit Agreement to a range of (A) 1.25% to 2.25% for LIBOR based borrowings and (B) 0.25% to 1.25% for alternative base rate based borrowings, with the specific applicable margins determined by reference to borrowing base utilization, (iii) reduce the frequency of scheduled borrowing base redeterminations from semi-annually to annually in certain circumstances, (iv) remove the cap on the amount of additional indebtedness allowed in the form of unsecured senior notes, (v) provide additional flexibility, subject to certain conditions, to make restricted payments, (vi) provide enhanced flexibility, subject to certain dollar limitations, to make investments in unrestricted subsidiaries and joint ventures and to make other investments, (vii) permit, subject to certain conditions, the dispositions of equity interests in unrestricted subsidiaries and (viii) amend certain other negative covenants.

Capital Expenditures

Our drilling, completions and infrastructure activities are capital intensive and require us to make substantial capital expenditures, which vary from year to year. For further information about our capital expenditures, see "—Capital Requirements and Sources of Liquidity."

The following table sets forth our capital expenditures for drilling, completions and infrastructure for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Capital expenditures	$477,111	$294,939	$901,197	$483,405

Our capital expenditures for drilling, completions and infrastructure (including facility buildout) were $1,207.4 million for the year ended December 31, 2017, of which our aggregate drilling and completion expenditures were $1,049.6 million and our infrastructure and other expenditures were $157.8 million.

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

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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.

Impact of ASC Topic 606 Adoption

We adopted ASC 606 effective January 1, 2018 using the modified retrospective approach. As a result, we changed our accounting policy for revenue recognition, which resulted in the following adjustments:

	Three Months Ended June 30, 2018		
	ASC 605	Adjustment	ASC 606
Production revenues (in thousands):			
Oil sales	$396,325	$ —	$396,325
Natural gas sales [(1)]	11,094	1,141	12,235
Natural gas liquids sales [(1)]	51,945	5,330	57,275
Total production revenues	459,364	6,471	465,835
Operating expenses			
Transportation and processing costs	—	6,471	6,471
Production revenues less transportation and processing costs	$459,364	$ —	$459,364
Net income attributable to Parsley, Inc. stockholders (in thousands)	$119,155	$ —	$119,155
Production:			
Oil (MBbls)	6,165	—	6,165
Natural gas (MMcf) [(1)]	8,287	948	9,235
Natural gas liquids (MBbls) [(1)]	1,853	253	2,106
Total (MBoe)	9,399	412	9,811
Average daily production volume:			
Oil (Bbls)	67,747	—	67,747
Natural gas (Mcf)	91,066	10,418	101,484
Natural gas liquids (Bbls)	20,363	2,780	23,143
Total (Boe)	103,286	4,527	107,813
Certain unit costs (per Boe) [(2)]:			
Lease operating expenses	$3.82	$ (0.16)	$3.66
Transportation and processing costs	$—	$ 0.66	$0.66
Production and ad valorem taxes	$2.91	$ (0.12)	$2.79
Depreciation, depletion and amortization	$15.49	$ (0.65)	$14.84
General and administrative expenses	$3.83	$ (0.16)	$3.67

(1) Natural gas and NGLs sales and production volumes for the three months ended June 30, 2018 reflect adjustments

associated with our adoption of ASC 606, effective January 1, 2018.

(2) Average costs per Boe for the three months ended June 30, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

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	Six Months Ended June 30, 2018		
	ASC 605	Adjustment	ASC 606
Production revenues (in thousands):			
Oil sales	$727,428	$ —	$727,428
Natural gas sales (1)	26,680	2,979	29,659
Natural gas liquids sales (1)	88,136	9,759	97,895
Total production revenues	842,244	12,738	854,982
Operating expenses			
Transportation and processing costs	—	12,738	12,738
Production revenues less transportation and processing costs	$842,244	$ —	$842,244
Net income attributable to Parsley, Inc. stockholders (in thousands)	$202,045	$ —	$202,045
Production:			
Oil (MBbls)	11,506	—	11,506
Natural gas (MMcf) (1)	16,269	1,522	17,791
Natural gas liquids (MBbls) (1)	3,317	432	3,749
Total (MBoe)	17,534	687	18,221
Average daily production volume:			
Oil (Bbls)	63,569	—	63,569
Natural gas (Mcf)	89,884	8,409	98,293
Natural gas liquids (Bbls)	18,326	2,387	20,713
Total (Boe)	96,873	3,796	100,669
Certain unit costs (per Boe) (2):			
Lease operating expenses	$3.70	$ (0.15)	$3.55
Transportation and processing costs	$—	$ 0.70	$0.70
Production and ad valorem taxes	$2.94	$ (0.11)	$2.83
Depreciation, depletion and amortization	$15.21	$ (0.57)	$14.64
General and administrative expenses	$4.05	$ (0.15)	$3.90

(1) Natural gas and NGLs sales and production volumes for the six months ended June 30, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1,

2018.

(2) Average costs per Boe for the six months ended June 30, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

Changes to natural gas and NGLs sales were made in accordance with the control model defined in ASC 606. Under the new control model, we are required to identify and separately analyze each contract associated with revenues to determine the appropriate accounting application. We considered various indicators for contracts and the weighting of their relevance to determine when control transferred to the customer (such as whether raw gas is sold at the receipt point or residue gas and NGLs are sold at the tailgate of the gas processing plants). Based on this analysis, we concluded that the presence of product redelivery and take-in-kind rights, if substantive, are determinative indicators of control transferring at the tailgate if there is intent at contract inception. Additionally, we consider risk of loss an important indicator of when control transfers, which is comprised of risks associated with loss of product, exposure to product mix and recoveries and exposure to index prices versus actual prices. We also concluded that title, custody and acceptance are not determinative indicators of control, as such factors may be present in the case of a sale or the performance of a service.

As a result of this analysis, we modified our accounting and presentation of natural gas and NGLs sales, and transportation and processing costs, under certain marketing agreements. This is due to the conclusion that we represent the principal and the ultimate third party is our customer, which implies that we maintain control of the product through the tailgate

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of gas processing plants in certain natural gas processing and marketing agreements with certain midstream entities in accordance with the control model in ASC 606. This is a change from previous conclusions we reached for these agreements when utilizing the principal versus agent indicators under ASC Topic 605, Revenue Recognition, where we acted as the agent and the midstream processing entity acted as our customer. As a result, our presentation of revenues and expenses for these agreements has been modified. Revenues related to these agreements are now presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Transportation and processing costs related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are now presented as Transportation and processing costs on our condensed consolidated statements of operations. Additionally, all references to production and per Boe unit costs reflect this adoption, which has the effect of increasing certain natural gas and NGLs volumes and revenues, offset by a corresponding transportation and processing expense, such that there is no change to reported net income. Refer to Note 2—Summary of Accounting Policies—Impact of ASC Topic 606 Adoption in our condensed consolidated financial statements for additional discussion.

All comparisons to prior period sales, expenses, production volumes and unit costs reflect the changes in reporting methodology for the three and six months ended June 30, 2018. To provide additional insight, in the above tables, we have quantified the impact of the adoption of ASC 606 during the three and six months ended June 30, 2018.

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Results of Operations

Revenues

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Production revenues (in thousands):				
Oil sales	$396,325	$178,066	$727,428	$347,811
Natural gas sales (1)	12,235	12,983	29,659	25,450
Natural gas liquids sales (1)	57,275	20,336	97,895	37,749
Total revenues	$465,835	$211,385	$854,982	$411,010
Average realized prices (2):				
Oil, without realized derivatives (per Bbls)	$64.29	$45.46	$63.22	$47.57
Oil, with realized derivatives (per Bbls)	60.11	45.49	59.28	46.90
Natural gas, without realized derivatives (per Mcf)	1.32	2.39	1.67	2.59
Natural gas, with realized derivatives (per Mcf)	1.40	2.36	1.72	2.56
Natural gas liquids (per Bbls)	27.20	19.02	26.11	20.20
Average price per Boe, without realized derivatives	47.48	35.89	46.92	37.98
Average price per Boe, with realized derivatives	44.92	35.87	44.48	37.50
Production:				
Oil (MBbls)	6,165	3,917	11,506	7,311
Natural gas (MMcf) (1)	9,235	5,421	17,791	9,840
Natural gas liquids (MBbls) (1)	2,106	1,069	3,749	1,869
Total (MBoe)	9,811	5,890	18,221	10,821
Average daily production volume:				
Oil (Bbls)	67,747	43,044	63,569	40,392
Natural gas (Mcf)	101,484	59,571	98,293	54,365
Natural gas liquids (Bbls)	23,143	11,747	20,713	10,326
Total (Boe)	107,813	64,725	100,669	59,785

(1) Natural gas and NGLs sales and associated production volumes for the three and six months ended June 30, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018, as discussed in Factors Affecting the Comparability of our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption.

(2) 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 table below shows, for the periods indicated, our average realized oil price as a percentage of the average NYMEX oil price, our average realized natural gas price as a percentage of the average NYMEX gas price, and our average realized NGLs price as a percentage of the average NYMEX oil price. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil, natural gas and NGLs revenues. Realized oil, natural gas and NGLs prices are the actual prices realized at the wellhead adjusted for quality, transportation fees and costs, differentials, marketing premiums or deductions and other factors that affect the price received at the wellhead.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Average realized oil price ($/Bbl)	$64.29	$45.46	$63.22	$47.57
Average NYMEX ($/Bbl)	$62.89	$51.78	$65.48	$49.95
Differential to NYMEX	$1.40	$(6.32)	$(2.26)	$(2.38)
Average realized oil price as a percentage of average NYMEX oil price	102%	88%	97%	95%
Average realized natural gas price ($/Mcf)	$1.32	$2.39	$1.67	$2.59
Average NYMEX ($/Mcf)	$2.83	$3.14	$2.84	$3.10
Differential to NYMEX	$(1.51)	$(0.75)	$(1.17)	$(0.51)
Average realized natural gas price as a percentage of average NYMEX gas price	47%	76%	59%	84%
Average realized NGLs price ($/Bbl)	$27.20	$19.02	$26.11	$20.20
Average NYMEX ($/Bbl)	$62.89	$51.78	$65.48	$49.95
Differential to NYMEX	$(35.69)	$(32.76)	$(39.37)	$(29.75)
Average realized NGLs price as a percentage of average NYMEX oil price	43%	37%	40%	40%

Oil, natural gas and NGLs revenues. Our oil, natural gas and NGLs revenues increased by $254.5 million, or 120%, to $465.8 million for the three months ended June 30, 2018 from $211.4 million for the three months ended June 30, 2017.

As shown in the following tables, from the three months ended June 30, 2017 to the three months ended June 30, 2018, the net dollar effect of the increase in oil and NGLs prices, as offset by the decrease in natural gas prices, was $123.4 million and the net dollar effect of the increase in production volumes of oil, natural gas and NGLs was $131.1 million. Included in these changes are increases of $1.1 million and $5.3 million for natural gas and NGLs sales, respectively, which are related to the adoption of ASC 606 as discussed in Note 2—Summary of Accounting Policies to our condensed consolidated financial statements included elsewhere in this Quarterly Report.

Effect of change in price:	Change in prices	Production volumes (in thousands)	Total net dollar effect of change (in thousands)
Oil (per Bbls)	$18.83	6,165	$116,065
Natural gas (per Mcf)	(1.07)	9,235	(9,882)
Natural gas liquids (per Bbls)	8.18	2,106	17,212
Total revenues due to change in price			$123,395

Effect of change in production volumes:	Change in production volumes (in thousands)	Prior period average prices	Total net dollar effect of change (in thousands)

Oil (MBbls)	2,248	$ 45.46	$ 102,194
Natural gas (MMcf)	3,814	2.39	9,134
Natural gas liquids (MBbls)	1,037	19.02	19,727
Total revenues due to change in production volumes			$ 131,055

Our oil, natural gas and NGLs revenues increased by $444.0 million, or 108%, to $855.0 million for the six months ended June 30, 2018 from $411.0 million for the six months ended June 30, 2017.

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As shown in the following tables, from the six months ended June 30, 2017 to the six months ended June 30, 2018, the net dollar effect of the increase in oil and NGLs prices as offset by the decrease in natural gas prices was $185.9 million and the net dollar effect of the increase in production volumes of oil, natural gas and NGLs was $258.1 million. Included in these changes are increases of $3.0 million and $9.8 million for natural gas and NGLs sales, respectively, which are related to the adoption of ASC 606 for the six months ended June 30, 2018 as discussed in Note 2—Summary of Accounting Policies to our condensed consolidated financial statements included elsewhere in this Quarterly Report.

	Change in prices	Production volumes	Total net dollar effect of change
Effect of change in price:		(in thousands)	(in thousands)
Oil (per Bbls)	$ 15.65	$ 11,506	$ 180,045
Natural gas (per Mcf)	(0.92)	17,791	(16,355)
Natural gas liquids (per Bbls)	5.91	3,749	22,175
Total revenues due to change in price			$ 185,865

	Change in production volumes	Prior period average prices	Total net dollar effect of change
Effect of change in production volumes:	(in thousands)		(in thousands)
Oil (MBbls)	4,195	$ 47.57	$ 199,572
Natural gas (MMcf)	7,951	2.59	20,564
Natural gas liquids (MBbls)	1,880	20.20	37,971
Total revenues due to change in production volumes			$ 258,107

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Operating expenses

The following table summarizes our expenses for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Operating expenses (in thousands):				
Lease operating expenses	$35,904	$29,631	$64,736	$47,258
Transportation and processing costs	6,471	—	12,738	—
Production and ad valorem taxes	27,331	11,397	51,517	22,559
Depreciation, depletion and amortization	145,552	83,315	266,751	152,285
General and administrative expenses (1)	35,991	31,761	70,986	55,803
Exploration and abandonment costs	3,366	2,442	8,777	5,205
Acquisition costs	(2)	7,176	2	8,520
Accretion of asset retirement obligations	359	193	713	329
Other operating expenses	2,477	2,503	4,652	4,786
Total operating expenses	$257,449	$168,418	$480,872	$296,745
Expense per Boe(2):				
Lease operating expenses	$3.66	$5.03	$3.55	$4.37
Transportation and processing costs	0.66	—	0.70	—
Production and ad valorem taxes	2.79	1.93	2.83	2.08
Depreciation, depletion and amortization	14.84	14.15	14.64	14.07
General and administrative expenses	3.67	5.39	3.90	5.16
Exploration and abandonment costs	0.34	0.41	0.48	0.48
Acquisition costs	—	1.22	—	0.79
Accretion of asset retirement obligations	0.04	0.03	0.04	0.03
Other operating expenses	0.25	0.42	0.26	0.44
Total operating expenses per Boe	$26.25	$28.58	$26.40	$27.42

(1) General and administrative expenses include stock-based compensation expense of $5.4 million and $10.4 million for the three and six months ended June 30, 2018, respectively, as compared to $5.3 million and $9.5 million for the three and six months ended June 30, 2017, respectively.

(2) All unit costs for the three and six months ended June 30, 2018 reflect the adoption of ASC 606, which had the effect of increasing certain natural gas and NGLs volumes. In turn, the increase in natural gas and NGLs volumes effectively decreased unit costs by approximately 4%.

Lease operating expenses. Lease operating expenses were $35.9 million and $64.7 million for the three and six months ended June 30, 2018, respectively, as compared to $29.6 million and $47.3 million for the three and six months ended June 30, 2017, respectively. The increase is primarily due to the increase in the number of our operated and non-operated wells.

On a per Boe basis, lease operating expenses decreased $1.37 per Boe, or 27%, to $3.66 for the three months ended June 30, 2018 from $5.03 for the three months ended June 30, 2017. 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 expenses per Boe is also partially attributable to a 67% increase in production period over period.

On a per Boe basis, lease operating expenses decreased $0.82 per Boe, or 19%, to $3.55 for the six months ended June 30, 2018 from $4.37 for the six months ended June 30, 2017. 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 expenses per Boe is also partially attributable to a 68% increase in production period over period.

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Transportation and processing costs. Transportation and processing costs were $6.5 million and $12.7 million for the three and six months ended June 30, 2018, respectively. On a per Boe basis, transportation and processing costs were $0.66 and $0.70 per Boe for the three and six months ended June 30, 2018, respectively. Transportation and processing costs represent third-party costs related to certain of our natural gas and NGLs marketing and processing agreements. Due to the adoption of ASC 606, we now report such costs separately. During the three and six months ended June 30, 2017, these costs were included in our net natural gas and NGLs sales. Refer to Note 2—Summary of Accounting Policies—Impact of ASC Topic 606 Adoption in our condensed consolidated financial statements for additional discussion.

Production and ad valorem taxes. Production and ad valorem taxes were $27.3 million and $51.5 million for the three and six months ended June 30, 2018, respectively, as compared to $11.4 million and $22.6 million for the three and six months ended June 30, 2017, respectively. On a per Boe basis, production and ad valorem taxes increased from $1.93 per Boe for the three months ended June 30, 2017 to $2.79 per Boe for the three months ended June 30, 2018 and from $2.08 per Boe for the six months ended June 30, 2017 to $2.83 per Boe for the six months ended June 30, 2018.

Overall, for the three and six months ended June 30, 2018, compared to the same periods in 2017, production taxes increased by approximately $12.4 million and $21.5 million, respectively, reflecting increased production during the periods and ad valorem taxes increased $3.5 million and $7.5 million over the same periods, reflecting higher property valuation assessments by local taxing authorities.

Depreciation, depletion and amortization. Depreciation, depletion and amortization (“DD&A”) expense was $145.6 million and $266.8 million for the three and six months ended June 30, 2018, respectively, as compared to $83.3 million and $152.3 million for the three and six months ended June 30, 2017, respectively.

These increases are largely attributable to acquisitions and development activity that resulted in a $2,153.3 million increase in costs subject to depletion as of June 30, 2018 as compared to June 30, 2017 and 67% and 68% increases in production during the three and six months ended June 30, 2018, respectively, as compared to the same periods in 2017. These increases were partially offset by a 55% increase in total proved reserves and a 58% increase in proved developed reserves as of June 30, 2018, as compared to June 30, 2017.

On a per Boe basis, DD&A expense increased to $14.84 for the three months ended June 30, 2018 from $14.15 during the three months ended June 30, 2017, and DD&A expense increased to $14.64 during the six months ended June 30, 2018 from $14.07 during the six months ended June 30, 2017, in each case primarily due to the increase in production volumes and reserves discussed above.

General and administrative expenses. General and administrative expenses were $36.0 million and $71.0 million for the three and six months ended June 30, 2018, respectively, as compared to $31.8 million and $55.8 million for the three and six months ended June 30, 2017, respectively. The increase is primarily due to higher payroll and stock-based compensation expenses associated with the hiring of additional employees to manage our growing asset base, recent acquisitions and increased production. General and administrative expenses per Boe were $3.67 and $3.90 for the three and six months ended June 30, 2018, respectively, as compared to $5.39 and $5.16 during the three and six months ended June 30, 2017,respectively, in each case primarily as a result of production volume growth outpacing general and administrative expenses growth.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Leasehold abandonments	$3,144	$—	$8,323	$—
Geological and geophysical costs	118	2,342	310	3,716
Idle drilling rig fees	—	(91)	—	1,070
Other	104	191	144	419
Total exploration and abandonment costs	$3,366	$2,442	$8,777	$5,205

During the three and six months ended June 30, 2018, we recognized leasehold abandonment expenses of approximately $3.1 million and $8.3 million, which primarily relates to expired acreage and expiring acreage determined to be outside of our economically productive reserves. No such expenses were incurred during the three and six months ended June 30, 2017.

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We recognized geological and geophysical ("G&G") costs of $0.1 million and $0.3 million during the three and six months ended June 30, 2018, respectively, as compared to costs of $2.3 million and $3.7 million during the three and six months ended June 30, 2017, respectively. Our G&G costs consist of the expenses associated with acquiring and processing seismic data, geophysical data and core analysis, primarily relating to geoscientific analysis of our acreage. The decrease in G&G costs during the three and six months ended June 30, 2018 reflects a reduction in our G&G related activity.

We recognized other exploration costs of $0.1 million and $0.1 million during the three and six months ended June 30, 2018, respectively, as compared to $0.2 million and $0.4 million during the three and six months ended June 30, 2017, respectively, which, in each case, are related to other exploration costs, which includes research and other similar costs.

During the three and six months ended June 30, 2017, exploration costs included idle drilling rig fees that were not chargeable to our joint operations. The applicable drilling rig contract expired on March 31, 2017, and no such fees were incurred during the three and six months ended June 30, 2018.

Acquisition costs. During the three and six months ended June 30, 2017, we incurred $7.2 million and $8.5 million, respectively, of acquisition costs which include non-recurring legal and other due diligence fees associated with certain acquisitions. During the three and six months ended June 30, 2018, such acquisition costs were minimal.

Other operating expenses. During the three and six months ended June 30, 2018, other operating expenses, which are primarily related to operating expenses incurred during the normal course of business of our majority-owned subsidiary, Pacesetter, were $2.5 million and $4.7 million, respectively, as compared to $2.5 million and $4.8 million during the three and six months ended June 30, 2017.

Other income (expense)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Other income (expense) (in thousands):				
Interest expense, net	$(33,758)	$(22,764)	$(65,726)	$(42,100)
Gain on sale of property	5,166	—	5,055	—
Loss on early extinguishment of debt	—	—	—	(3,891)
(Loss) gain on derivatives	(9,466)	43,514	(20,259)	68,130
Change in TRA liability	—	—	(82)	(20,549)
Interest income	1,686	2,178	3,809	4,549
Other income (loss)	234	(177)	535	773
Total other income (expense), net	$(36,138)	$22,751	$(76,668)	$6,912

Interest expense, net. Interest expense, net for the three and six months ended June 30, 2018 was $33.8 million and $65.7 million, respectively, as compared to $22.8 million and $42.1 million, respectively, for the three and six months ended June 30, 2017. The increase resulted from increased weighted average debt outstanding, as discussed in Note 7—Debt to our condensed consolidated financial statements included elsewhere in this Quarterly Report.

Gain on sale of property. We recognized a gain on the sale of property of $5.2 million and $5.1 million during the three and six months ended June 30, 2018, respectively, as discussed in Note 5—Acquisitions and Divestitures to our condensed consolidated financial statements included elsewhere in this Quarterly Report. We recognized no gain or loss on the sale of property during the three and six months ended June 30, 2017.

Loss on early extinguishment of debt. We recorded a $3.9 million loss on early extinguishment of debt during the six months ended June 30, 2017 due to the redemption of our then outstanding 7.500% senior unsecured notes due 2022 in January 2017. There was no such activity for the three and six months ended June 30, 2018 or the three months ended June 30, 2017.

(Loss) gain on derivatives. We recognized a loss on derivatives of $9.5 million and $20.3 million, respectively, during the three and six months ended June 30, 2018, respectively, and a gain on derivatives of $43.5 million and $68.1 million during the three and six months ended June 30, 2017, respectively. The change during the three and six months ended June 30, 2018,

as compared to the three and six months ended June 30, 2017, is primarily a result of higher commodity prices, which decreased the value of our derivative portfolio.

Change in TRA liability. We recorded a $0.1 million expense during the six months ended June 30, 2018, respectively, associated with an increase in the TRA liability resulting from the reversal of the valuation allowance recorded during 2017. During the six months ended June 30, 2017 we recorded a $20.5 million expense associated with an increase in the TRA liability resulting from the reversal of the valuation allowance recorded during 2016. During the three months ended June 30 2018 and 2017, we recorded no change to the TRA liability.

Interest income. Interest income was $1.7 million and $3.8 million during the three and six months ended June 30, 2018, respectively, as compared to $2.2 million and $4.5 million during the three and six months ended June 30, 2017, respectively. The change during the three and six months ended June 30, 2018, as compared to the three and six months ended June 30, 2017, is a result of decreased dividend and interest income offset by increased amortization, which relates to our held to maturity securities, as discussed in Note 14—Disclosures about Fair Value of Financial Instruments.

Other income (loss). Other income was $0.2 million, $0.5 million and $0.8 million for the three and six months ended June 30, 2018 and the six months ended June 30, 2017, respectively. Other loss was $0.2 million for the three months ended June 30, 2017. The increase for the three months ended June 30, 2018, as compared to the same respective period in 2017 is attributable to an increase in income from our equity investment in Spraberry Production Services, LLC as well as a small increase in other miscellaneous items. The decrease for the six months ended June 30, 2018, as compared to the same respective period in 2017, is primarily attributable to a decrease in fair value adjustments associated with money market accounts as well as a decrease in income from our equity investment in Spraberry Production Services, LLC.

Income Tax Expense

During the three and six months ended June 30, 2018, we recognized income tax expense of $33.2 million and $56.6 million, respectively. During the three and six months ended June 30, 2017, we recognized income tax expense of $12.2 million and $30.6 million, respectively. These changes were attributable to the changes in our results of operations, discussed above, as well as the impact of net income attributable to noncontrolling ownership interests and state income taxes.

Capital Requirements and Sources of Liquidity

The following table sets forth our capital expenditures for drilling, completions and infrastructure for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Capital expenditures	$477,111	$294,939	$901,197	$483,405

Our 2018 budget for capital development expenditures is approximately $1,650.0 million to $1,750.0 million, which represents an increase from our previously disclosed 2018 budget for capital development expenditures of $1,350 million to $1,550.0 million. Approximately 85% to 90% of the budget is expected to be used for drilling and completions and approximately 10% to 15% of the budget is expected to be used for infrastructure and other expenditures. Our capital budget excludes any amounts that may be paid for acquisitions. For the year ended December 31, 2017, our aggregate drilling and completion expenditures were $1,049.6 million and our infrastructure and other expenditures were $157.8 million for a total of $1,207.4 million. The amount and timing of 2018 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2018 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 current oil and natural gas price expectations for fiscal year 2018, we believe that our cash on hand, cash flow from operations and borrowings under the Revolving Credit Agreement will be sufficient to fund our operations through 2018. However, as more fully described below, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and the significant capital expenditures required to more fully develop our properties. As of June 30, 2018, our liquidity was as follows (in millions):

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Cash and cash equivalents	$201.7
Short-term investments	99.7
Revolving Credit Agreement availability	991.3
Liquidity	$1,292.7

Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and the significant capital expenditures 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, 2017 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 2018 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 or 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,	
	2018	2017
Net cash provided by operating activities	$490,981	$327,204
Net cash used in investing activities	(831,091)	(2,456,621)
Net cash (used in) provided by financing activities	(12,377)	2,499,253

Cash flows provided by operating activities. Net cash provided by operating activities was approximately $491.0 million and $327.2 million for the six months ended June 30, 2018 and 2017, respectively. Net cash provided by operating activities increased primarily due to a $446.0 million increase in total revenues during the six months ended June 30, 2018 over the six months ended June 30, 2017, offset by a $64.7 million increase in cash based operating expenses, including lease operating expenses, transportation and processing costs, production and ad valorem taxes, cash general and administrative expenses and acquisition costs, as well as a $175.6 million increase in funds used to satisfy working capital obligations.

Cash flows used in investing activities. Net cash used in investing activities was approximately $831.1 million and $2,456.6 million for the six months ended June 30, 2018 and 2017, respectively. The reduction in the amount of cash used in investing activities was due primarily to the $2,032.3 million decrease in acquisition costs during the six months ended June 30, 2018 over the six months ended June 30, 2017, offset by the $492.5 million increase in development costs related to our oil and natural gas properties during the six months ended June 30, 2018 over the six months ended June 30, 2017. Please refer to Note 5—Acquisitions and Divestitures to our condensed consolidated financial statements included elsewhere in this Quarterly Report for additional discussion related to acquisitions.

Cash flows (used in) provided by financing activities. Net cash used in financing activities was $12.4 million and net cash provided by financing activities was $2,499.3 million for the six months ended June 30, 2018 and 2017, respectively. Net cash provided by financing activities decreased by $2,511.6 million during the six months ended June 30, 2018 as a result of the Company not completing any debt or equity issuances in the period. During the six months ended June 30, 2018, we had payments on long-term debt of $1.5 million and $10.9 million related to the vesting of RSUs and PSUs, respectively. During the six months ended June 30, 2017, we received net proceeds from equity offerings of $2,123.5 million and net proceeds from debt offerings of $443.3 million, which were offset by payments on long-term debt of $67.4 million.

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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.

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 6.250% senior unsecured notes due 2024.

5.375% Senior Unsecured Notes due 2025. See Note 7—Debt to our condensed consolidated financial statements included elsewhere in this Quarterly Report for information regarding our 5.375% senior unsecured notes due 2025.

5.250% Senior Unsecured Notes due 2025. See Note 7—Debt to our condensed consolidated financial statements included elsewhere in this Quarterly Report for information regarding our 5.250% senior unsecured notes due 2025.

5.625% Senior Unsecured Notes due 2027. See Note 7—Debt to our condensed consolidated financial statements included elsewhere in this Quarterly Report for information regarding our 5.625% senior unsecured notes due 2027.

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 and natural gas production.

Working Capital

Our working capital totaled ($45.4) million and $307.4 million at June 30, 2018 and December 31, 2017, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash and cash equivalents and short-term investments totaled $301.4 million and $703.5 million at June 30, 2018 and December 31, 2017, respectively. The $402.1 million decrease in cash and cash equivalents and short-term investments is primarily attributable to the development of our oil and natural gas properties as well as acquisitions described in Note 5—Acquisitions and Divestitures to our condensed consolidated financial statements included elsewhere in this Quarterly Report. 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 continue to 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, 2018 to the methodology applied by management for critical accounting policies previously disclosed in the Annual Report. Please read “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates” in the Annual Report for further description of our critical accounting policies.

Off-Balance Sheet Arrangements

We do not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the notes to our condensed consolidated financial statements.

Contractual Obligations

We had no material changes in our contractual commitments and obligations from amounts listed under “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity—Contractual Obligations” in our Annual Report on Form 10-K for the year ended December 31, 2017.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices 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 and natural gas production. Pricing for our production has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our 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.

We enter into multiple types of commodity derivative contracts to (i) reduce the effect of price volatility on our oil and natural gas revenues and (ii) support our annual capital budgeting and expenditure plans. 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, 2018, 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 typically enter into an International Swap Dealers Association Master Agreement ("ISDA Agreement") with 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, 2018, the fair market value of our oil and natural gas derivative contracts was a net liability of $29.6 million, including net deferred premium payables of $59.8 million. The deferred premium payable is a fixed amount and is not marked to fair market value. As of June 30, 2018, the fair market value of our oil derivative contracts was a net liability of $29.7 million. Based on our open oil derivative positions at June 30, 2018, a 10% increase in the NYMEX WTI price would increase our net oil derivative liability by approximately $36.0 million, while a 10% decrease in the NYMEX WTI price would decrease our net oil derivative liability by approximately $25.9 million. As of June 30, 2018, the fair market value of our natural gas derivative contracts was a net asset of $0.1 million. Based on our open natural gas derivative positions at June 30, 2018, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by $0.1 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas asset by $0.1 million. Please read "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—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 the 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 the Revolving Credit Agreement, each of whom has an investment grade rating.

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Interest Rate Risk

Our market risk exposure related to changes in interest rates relates primarily to debt obligations and the amount of interest we earn on our short-term investments. As of June 30, 2018, we had $2.2 billion (excluding capital lease obligations) of fixed-rate long-term debt outstanding with a weighted average interest rate of 5.6%. Although near term changes may impact the fair value of our fixed-rate debt, they do not expose us to interest rate risk or cash flow loss. We are exposed to changes in interest rates as a result of the Revolving Credit Agreement, which requires us to pay higher interest rate margins as we utilize a larger percentage of our available commitments. As of June 30, 2018, however, we had no outstanding borrowings under the 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 the Revolving Credit Agreement. We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents and short-term investment balances. As of June 30, 2018, our cash and cash equivalents and short-term investments totaled $301.4 million, approximately 75% of which was invested in money market funds and commercial paper with major financial institutions. A change in the interest rate applicable to the Revolving Credit Agreement or short-term investments would have a de minimis impact.

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Item 4. Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2018. 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, 2018, 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 Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended June 30, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" included in the Annual Report and the risk factors and other cautionary statements contained in our other SEC filings, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. There have been no material changes in our risk factors from those described in the 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 three months ended June 30, 2018:

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 2018	—	$ —	—	$ —
May 2018	149,788	$ 29.42	—	$ —
June 2018	—	$ —	—	$ —
Total	149,788	$ 29.42	—	$ —

(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.

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Item 5. Other Information

To ensure that our Board of Directors is divided into three classes, with each class as nearly equal in number as is reasonably possible, as mandated by our Certificate of Incorporation, effective August 3, 2018, Bryan Sheffield resigned from his position as a Class III director and immediately thereafter was appointed by the Board as a Class I director (the "Reclassification"). The Reclassification was effected in accordance with our Certificate of Incorporation and our Amended and Restated Bylaws, as amended. Except to the extent required to effect the Reclassification, Mr. Sheffield's service on the Board is deemed to have continued uninterrupted since his original election to the Board. Mr. Sheffield and the two continuing Class I directors will stand for election at our 2021 annual meeting of stockholders.
For a discussion of "related person" transactions (as such term is defined in Item 404(a) of Regulation S-K) with respect to Mr. Sheffield, please refer to "Transactions with Related Persons" commencing on page 49 of our definitive proxy statement filed with the SEC on April 6, 2018, which is incorporated herein by reference.

Item 6. Exhibits

The exhibits required to be filed by Item 6 are set forth in the Exhibit Index included below.

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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 3.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on November 2, 2016).
3.3	First Amendment to the Amended and Restated Bylaws 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 5, 2017).
10.1	Sixth Amendment to Credit Agreement, dated as of April 30, 2018, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (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 3, 2018).
10.2†	Indemnification Agreement, dated as of April 23, 2018, by and between Parsley Energy, Inc. and Rob Hembree (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on May 4, 2018).
10.3*†	Form of Director Agreement.
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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	PARSLEY ENERGY, INC.	
August 8, 2018	By:	/s/ Bryan Sheffield
		Bryan Sheffield
		Chairman and Chief Executive Officer
		(Principal Executive Officer)
August 8, 2018	By:	/s/ Ryan Dalton
		Ryan Dalton
		Executive Vice President—Chief Financial Officer
		(Principal Accounting and Financial Officer)