Oasis Petroleum Inc.
Form 10-Q
November 08, 2016
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-34776

Oasis Petroleum Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	80-0554627 (I.R.S. Employer Identification No.)
1001 Fannin Street, Suite 1500 Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

(281) 404-9500
(Registrant's telephone number, including area code)

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

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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Number of shares of the registrant's common stock outstanding at November 2, 2016: 236,365,219 shares.

Table of Contents

OASIS PETROLEUM INC.
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2016
TABLE OF CONTENTS

Table of Contents

PART I — FINANCIAL INFORMATION
Item 1. — Financial Statements (Unaudited)
Oasis Petroleum Inc.
Condensed Consolidated Balance Sheet
(Unaudited)

	September 30, 2016	December 31, 2015
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 13,776	$ 9,730
Accounts receivable — oil and gas revenues	103,128	96,495
Accounts receivable — joint interest and other	77,903	100,914
Inventory	8,513	11,072
Prepaid expenses	6,093	7,328
Derivative instruments	9,142	139,697
Other current assets	4,290	50
Total current assets	222,845	365,286
Property, plant and equipment		
Oil and gas properties (successful efforts method)	6,438,782	6,284,401
Other property and equipment	580,171	443,265
Less: accumulated depreciation, depletion, amortization and impairment	(1,866,280)	(1,509,424)
Total property, plant and equipment, net	5,152,673	5,218,242
Assets held for sale	—	26,728
Derivative instruments	194	15,776
Other assets	22,549	23,343
Total assets	$ 5,398,261	$ 5,649,375
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities		
Accounts payable	$ 7,929	$ 9,983
Revenues and production taxes payable	141,991	132,356
Accrued liabilities	98,926	167,669
Accrued interest payable	19,798	49,413
Derivative instruments	17,308	—
Advances from joint interest partners	5,191	4,647
Other current liabilities	—	6,500
Total current liabilities	291,143	370,568
Long-term debt	2,125,573	2,302,584
Deferred income taxes	546,202	608,155
Asset retirement obligations	37,092	35,338
Liabilities held for sale	—	10,228
Derivative instruments	7,755	—
Other liabilities	2,992	3,160
Total liabilities	3,010,757	3,330,033
Commitments and contingencies (Note 15)		
Stockholders’ equity		
Common stock, $0.01 par value: 450,000,000 and 300,000,000 shares authorized at September 30, 2016 and December 31, 2015, respectively; 182,038,164 shares issued and 181,186,070 shares outstanding at September 30, 2016 and 139,583,990 shares	1,779	1,376

issued and 139,076,064 shares outstanding at December 31, 2015		
Treasury stock, at cost: 852,094 and 507,926 shares at September 30, 2016 and December 31, 2015, respectively	(15,895)	(13,620)
Additional paid-in capital	1,755,427	1,497,065
Retained earnings	646,193	834,521
Total stockholders’ equity	2,387,504	2,319,342
Total liabilities and stockholders’ equity	$ 5,398,261	$ 5,649,375

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

1

Table of Contents

Oasis Petroleum Inc.
Condensed Consolidated Statement of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$158,183	$175,270	$434,835	$563,239
Well services and midstream revenues	19,128	21,965	51,839	44,429
Total revenues	177,311	197,235	486,674	607,668
Operating expenses				
Lease operating expenses	35,696	35,670	98,283	112,556
Well services and midstream operating expenses	8,165	10,023	21,429	19,370
Marketing, transportation and gathering expenses	8,856	8,465	23,899	23,313
Production taxes	14,638	16,676	39,758	53,915
Depreciation, depletion and amortization	111,948	123,734	356,885	361,430
Exploration expenses	489	327	1,192	2,252
Rig termination	—	—	—	3,895
Impairment	382	80	3,967	24,917
General and administrative expenses	22,845	22,358	69,087	67,190
Total operating expenses	203,019	217,333	614,500	668,838
Gain (loss) on sale of properties	6	172	(1,305)	172
Operating loss	(25,702)	(19,926)	(129,131)	(60,998)
Other income (expense)				
Net gain (loss) on derivative instruments	20,847	103,637	(55,624)	111,285
Interest expense, net of capitalized interest	(31,726)	(36,513)	(105,444)	(112,702)
Gain (loss) on extinguishment of debt	(13,793)	—	4,865	—
Other income (expense)	(259)	249	188	370
Total other income (expense)	(24,931)	67,373	(156,015)	(1,047)
Income (loss) before income taxes	(50,633)	47,447	(285,146)	(62,045)
Income tax benefit (expense)	16,691	(20,392)	96,818	17,829
Net income (loss)	$(33,942)	$27,055	$(188,328)	$(44,216)
Earnings (loss) per share:				
Basic (Note 13)	$(0.19)	$0.20	$(1.09)	$(0.35)
Diluted (Note 13)	(0.19)	0.20	(1.09)	(0.35)
Weighted average shares outstanding:				
Basic (Note 13)	177,120	137,014	172,360	127,827
Diluted (Note 13)	177,120	137,014	172,360	127,827

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

Table of Contents

Oasis Petroleum Inc.
Condensed Consolidated Statement of Changes in Stockholders' Equity
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount			
	(In thousands)						
Balance at December 31, 2015	139,076	$ 1,376	508	$ (13,620)	$ 1,497,065	$ 834,521	$ 2,319,342
Issuance of common stock	39,100	391	—	—	182,400	—	182,791
Stock-based compensation	3,354		—	—	20,109	—	20,109
Vesting of restricted shares	—	12	—	—	(12)	—	—
Equity component of senior unsecured convertible notes, net	—	—	—	—	55,865	—	55,865
Treasury stock – tax withholdings	(344)	—	344	(2,275)	—	—	(2,275)
Net loss	—	—	—	—	—	(188,328)	(188,328)
Balance at September 30, 2016	181,186	$ 1,779	852	$ (15,895)	$ 1,755,427	$ 646,193	$ 2,387,504

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

Table of Contents

Oasis Petroleum Inc.
Condensed Consolidated Statement of Cash Flows
(Unaudited)

	Nine Months Ended September 30, 2016	2015
	(In thousands)	
Cash flows from operating activities:		
Net loss	$(188,328)	$(44,216)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	356,885	361,430
Gain on extinguishment of debt	(4,865)	—
(Gain) loss on sale of properties	1,305	(172)
Impairment	3,967	24,917
Deferred income taxes	(96,818)	(17,829)
Derivative instruments	55,624	(111,285)
Stock-based compensation expenses	18,761	19,629
Deferred financing costs amortization and other	10,174	7,468
Working capital and other changes:		
Change in accounts receivable	11,349	108,309
Change in inventory	2,559	8,425
Change in prepaid expenses	1,168	638
Change in other current assets	(240)	5,529
Change in other assets	(148)	—
Change in accounts payable, interest payable and accrued liabilities	(41,991)	(84,133)
Change in other current liabilities	(6,000)	1,655
Change in other liabilities	17	(28)
Net cash provided by operating activities	123,419	280,337
Cash flows from investing activities:		
Capital expenditures	(340,314)	(740,633)
Proceeds from sale of properties	12,333	78
Costs related to sale of properties	(310)	—
Derivative settlements	115,576	291,436
Advances from joint interest partners	544	(1,239)
Net cash used in investing activities	(212,171)	(450,358)
Cash flows from financing activities:		
Proceeds from revolving credit facility	835,000	618,000
Principal payments on revolving credit facility	(778,000)	(938,000)
Repurchase of senior unsecured notes	(435,907)	—
Proceeds from issuance of senior unsecured convertible notes	300,000	—
Deferred financing costs	(8,811)	(3,587)
Proceeds from sale of common stock	182,791	462,833
Purchases of treasury stock	(2,275)	(2,771)
Net cash provided by financing activities	92,798	136,475
Increase (decrease) in cash and cash equivalents	4,046	(33,546)
Cash and cash equivalents:		
Beginning of period	9,730	45,811
End of period	$13,776	$12,265
Supplemental non-cash transactions:		

Change in accrued capital expenditures	$(49,177)	$(233,913)
Change in asset retirement obligations	(8,083)	3,405

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

Table of Contents

OASIS PETROLEUM INC.
Notes to Condensed Consolidated Financial Statements (Unaudited)
1. Organization and Operations of the Company
Oasis Petroleum Inc. (together with its consolidated subsidiaries, “Oasis” or the “Company”) was originally formed in 2007 and was incorporated pursuant to the laws of the State of Delaware in 2010. The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the North Dakota and Montana regions of the Williston Basin. Oasis Petroleum North America LLC (“OPNA”) conducts the Company’s exploration and production activities and owns its proved and unproved oil and natural gas properties. The Company also operates a well services business through Oasis Well Services LLC (“OWS”) and a midstream services business through Oasis Midstream Services LLC (“OMS”), both of which are separate reportable business segments that are complementary to its primary development and production activities.
2. Summary of Significant Accounting Policies
Basis of Presentation
The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. The accompanying condensed consolidated financial statements of the Company have not been audited by the Company’s independent registered public accounting firm, except that the Condensed Consolidated Balance Sheet at December 31, 2015 is derived from audited financial statements. In the opinion of management, all adjustments, consisting of normal recurring adjustments necessary for the fair statement, have been included. Management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.
These interim financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”) regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (“GAAP”) for complete consolidated financial statements and should be read in conjunction with the Company’s audited consolidated financial statements and notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2015 (“2015 Annual Report”).
Risks and Uncertainties
As an oil and natural gas producer, the Company’s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, political and regulatory developments and competition from other energy sources. The energy markets have historically been very volatile, and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. Oil and natural gas prices have declined significantly since mid-2014. As a result of sustained lower commodity prices, the Company decreased its 2016 capital expenditures, excluding acquisitions, as compared to 2015 and continues to concentrate its drilling activities in certain areas that are the most economic in the Williston Basin. An extended period of low prices for oil and, to a lesser extent, natural gas could have a material adverse effect on the Company’s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.
Significant Accounting Policies
There have been no material changes to the Company’s critical accounting policies and estimates from those disclosed in the 2015 Annual Report.
Recent Accounting Pronouncements
Revenue recognition. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, Deferral of the Effective Date (“ASU 2015-14”). ASU

2015-14 defers the effective date of the new revenue standard by one year, making it effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. In 2016, the FASB issued additional accounting standards updates to clarify the implementation guidance of ASU 2014-09. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Table of Contents

Going concern. In August 2014, the FASB issued Accounting Standards Update No. 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 codifies in GAAP management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual reporting period ending after December 15, 2016 and for annual periods and interim periods thereafter. The adoption of this guidance will not impact the Company's financial position, cash flows or results of operations but could result in additional disclosures.

Inventory. In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Simplifying the Measurement of Inventory ("ASU 2015-11"). ASU 2015-11 changes the inventory measurement principle from lower of cost or market to lower of cost and net realizable value for entities using the first-in, first-out or average cost methods. ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or results of operations.

Financial instruments. In January 2016, the FASB issued Accounting Standards Update No. 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01"), which requires that most equity instruments be measured at fair value with subsequent changes in fair value recognized in net income. ASU 2016-01 also impacts financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. ASU 2016-01 does not apply to equity method investments or investments in consolidated subsidiaries. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Leases. In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases ("ASU 2016-02"), which requires a lessee to recognize lease payment obligations and a corresponding right-of-use asset to be measured at fair value on the balance sheet. ASU 2016-02 also requires certain qualitative and quantitative disclosures about the amount, timing and uncertainty of cash flows arising from leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Embedded derivatives. In March 2016, the FASB issued Accounting Standards Update No. 2016-06, Contingent Put and Call Options in Debt Instruments ("ASU 2016-06"), which clarifies what steps are required when assessing whether the economic characteristics and risks of call (put) options are clearly and closely related to the economic characteristics and risks of their debt hosts, which is one of the criteria for bifurcating an embedded derivative. ASU 2016-06 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or results of operations.

Stock-based compensation. In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"), which updates several aspects of the accounting for share-based payment transactions, including recognition of excess tax benefits and deficiencies, the classification of those excess tax benefits on the statement of cash flows, an accounting policy election for forfeitures, the amount an employer can withhold to cover income taxes and still qualify for equity classification and the classification of those taxes paid on the statement of cash flows. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company will record a cumulative-effect adjustment to equity at the beginning of 2017 when the guidance is adopted and does not expect the adoption of this guidance to have a material impact on its cash flows or results of operations.

Statement of cash flows. In August 2016, the FASB issued Accounting Standards Update No. 2016-15, Statement of Cash Flows ("ASU 2016-15"), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. The adoption of this guidance will not impact the Company's financial position or results of operations but could result in presentation changes on the statement of cash flows.

3. Inventory

Crude oil inventory includes oil in tank and linefill. Equipment and materials consist primarily of proppant, chemicals, tubular goods, well equipment to be used in future drilling or repair operations and well fracturing equipment. Inventory is stated at the lower of cost or market value with cost determined on an average cost method. Inventory consists of the following:

	September 30, 2016	December 31, 2015
	(In thousands)	
Crude oil inventory	$5,344	$ 6,152
Equipment and materials	3,169	4,920
Total inventory	$8,513	$ 11,072

6

Table of Contents

4. Fair Value Measurements

In accordance with the FASB’s authoritative guidance on fair value measurements, the Company’s financial assets and liabilities are measured at fair value on a recurring basis. The Company recognizes its non-financial assets and liabilities, such as asset retirement obligations (“ARO”) and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

As defined in the authoritative guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The authoritative guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (“Level 1” measurements) and the lowest priority to unobservable inputs (“Level 3” measurements). The three levels of the fair value hierarchy are as follows:

Level 1 — Unadjusted quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs, other than unadjusted quoted prices in active markets included in Level 1, are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 — Pricing inputs are generally less observable from objective sources, requiring internally developed valuation methodologies that result in management’s best estimate of fair value.

Financial Assets and Liabilities

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:

	Fair value at September 30, 2016			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$54	$—	$ —	$54
Commodity derivative instruments (see Note 5)	—	9,336	—	9,336
Total assets	$54	$9,336	$ —	$9,390
Liabilities:				
Commodity derivative instruments (see Note 5)	$—	$25,063	$ —	$25,063
Total liabilities	$—	$25,063	$ —	$25,063

	Fair value at December 31, 2015			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				

Money market funds	$742	$—	$ —	$742
Commodity derivative instruments (see Note 5)	—	155,473	—	155,473
Total assets	$742	$155,473	$ —	$156,215

Table of Contents

The Level 1 instruments presented in the tables above consist of money market funds included in cash and cash equivalents on the Company's Condensed Consolidated Balance Sheet at September 30, 2016 and December 31, 2015. 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.

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include oil and natural gas swaps and collars. The fair values of the Company's commodity derivative instruments are based upon a third-party preparer's calculation using mark-to-market valuation reports provided by the Company's counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts, as there is an active market for these contracts. The third-party preparer performs its independent valuation using a moment matching method similar to Turnbull-Wakeman for Asian options. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The Company compares the third-party preparer's valuation to counterparty valuation statements, investigating any significant differences, and analyzes monthly valuation changes in relation to movements in crude oil and natural gas forward price curves. The determination of the fair value for derivative instruments also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculates the credit adjustment for derivatives in a net asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a net liability position is based on the Company's market credit spread. Based on these calculations, the Company recorded an adjustment to reduce the fair value of its net derivative liability by $1.2 million at September 30, 2016 and an adjustment to reduce the fair value of its net derivative asset by $0.3 million at December 31, 2015.

There were no transfers between fair value levels during the nine months ended September 30, 2016 and 2015.

Fair Value of Other Financial Instruments

The Company's financial instruments, including certain cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. At September 30, 2016, the Company's cash equivalents were all Level 1 assets.

The carrying amount of the Company's long-term debt reported in the Condensed Consolidated Balance Sheet at September 30, 2016 was $2,125.6 million, which included $2,053.0 million of senior unsecured notes, reductions for the unamortized debt discount related to the equity component of the senior unsecured convertible notes and the unamortized deferred financing costs on the senior unsecured notes of $92.9 million and $29.5 million, respectively, and $195.0 million of borrowings under the revolving credit facility (see Note 8 – Long-Term Debt). The fair value of the Company's senior unsecured notes, which are publicly traded and therefore categorized as Level 1 liabilities, was $2,018.0 million at September 30, 2016.

The Company determined the fair value of the liability component of the senior unsecured convertible notes as of their issuance dates by estimating the fair value of a similar debt instrument without the conversion feature (see Note 8 – Long-Term Debt). The significant inputs used were the market credit spread on the Company's senior unsecured notes with similar maturity dates, the risk-free interest rate and the terms of the senior unsecured convertible notes, which are directly observable in the marketplace, representing Level 2 inputs.

Non-Financial Assets and Liabilities

Asset retirement obligations. The carrying amount of ARO in the Company's Condensed Consolidated Balance Sheet at September 30, 2016 was $37.8 million (see Note 9 – Asset Retirement Obligations). The Company determines its ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding the timing and existence of a liability, as well as what constitutes adequate restoration when considering current regulatory requirements. Inherent in the fair value calculation are numerous assumptions and judgments, including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments.

These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.
Impairment. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its proved oil and natural gas properties and then compares such undiscounted future cash flows to the carrying amount of the proved oil and natural gas properties to determine if the carrying amount is

Table of Contents

recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the proved oil and natural gas properties to the fair value. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs, using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs.

On April 1, 2016, the Company sold certain proved oil and natural gas properties and other midstream properties (see Note 7 – Divestiture). For the nine months ended September 30, 2016, the Company recorded an impairment charge of $3.6 million, of which $2.4 million was included in its midstream services segment and $1.2 million was included in its exploration and production segment, to adjust the current carrying value of these assets, net of the associated ARO liabilities, to their estimated fair value. For the year ended December 31, 2015, the Company recorded an impairment charge of $9.4 million to adjust its net assets held for sale to their estimated fair value in its exploration and production segment. The fair value was determined based on the expected sales price, less costs to sell. No other impairment charges on proved oil and natural gas properties were recorded for the nine months ended September 30, 2016. No impairment charges on proved oil and natural gas properties were recorded for the three months ended September 30, 2016 and the three and nine months ended September 30, 2015.

In addition, as a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and natural gas properties of $0.4 million for both the three and nine months ended September 30, 2016, respectively, and $0.1 million and $24.9 million for the three and nine months ended September 30, 2015, respectively. The impairment charges included $0.2 million for both the three and nine months ended September 30, 2016 and $16.4 million for the nine months ended September 30, 2015 related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. For the three months ended September 30, 2015, the Company did not record similar impairment charges for unexpired leases.

Table of Contents

5. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil and natural gas prices. The Company's crude oil and natural gas contracts will settle monthly based on the average NYMEX West Texas Intermediate crude oil index price ("WTI") and the average NYMEX Henry Hub natural gas index price ("Henry Hub"), respectively. At September 30, 2016, the Company utilized swaps and two-way and three-way costless collar options to reduce the volatility of oil and natural gas prices on a significant portion of its future expected oil and natural gas production. A swap is a sold call and a purchased put established at the same price (both ceiling and floor). A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be the NYMEX index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract.

All derivative instruments are recorded on the Company's Condensed Consolidated Balance Sheet as either assets or liabilities measured at fair value (see Note 4 – Fair Value Measurements). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value are recognized in the other income (expense) section of the Company's Condensed Consolidated Statement of Operations as a net gain or loss on derivative instruments. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making a payment to or receiving a payment from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled. Cash settlements are reflected as investing activities in the Company's Condensed Consolidated Statement of Cash Flows.

At September 30, 2016, the Company had the following outstanding commodity derivative instruments:

Commodity	Settlement Period	Derivative Instrument	Volumes		Weighted Average Prices				Fair Value Asset (Liability)
					Swap	Sub-Floor	Floor	Ceiling	(In thousands)
Crude oil	2016	Swaps	2,973,000	Bbl	$49.18				$ 4,765
Crude oil	2017	Swaps	5,059,000	Bbl	$48.04				(14,742)
Crude oil	2017	Two-way collar	1,002,000	Bbl			$41.67	$50.58	(4,092)
Crude oil	2017	Three-way collar	1,670,000	Bbl		$ 30.00	$45.00	$60.11	241
Crude oil	2018	Swaps	522,000	Bbl	$50.07				(1,349)
Crude oil	2018	Two-way collar	93,000	Bbl			$41.67	$50.58	(471)
Crude oil	2018	Three-way collar	155,000	Bbl		$ 30.00	$45.00	$60.11	(122)
Natural gas	2017	Swaps	1,336,000	MMbtu	$3.12				52
Natural gas	2018	Swaps	124,000	MMbtu	$3.12				(9)
									$ (15,727)

The following table summarizes the location and fair value of all outstanding commodity derivative instruments recorded in the Company's Condensed Consolidated Balance Sheet:

Type	Balance Sheet Location	Fair Value Asset (Liability) September 30, 2016	December 31, 2015
		(In thousands)	
Commodity contracts	Derivative instruments — current assets	$9,142	$139,697
Commodity contracts	Derivative instruments — non-current assets	194	15,776
Commodity contracts	Derivative instruments — current liabilities	(17,308)	—

Commodity contracts	Derivative instruments — non-current liabilities	(7,755)	—
Total derivative instruments		$(15,727)	$155,473

Table of Contents

The following table summarizes the location and amounts of gains and losses from the Company's commodity derivative instruments recorded in the Company's Condensed Consolidated Statement of Operations for the periods presented:

Statement of Operations Location	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
	(In thousands)			
Net gain (loss) on derivative instruments	$20,847	$103,637	$(55,624)	$111,285

In accordance with the FASB's authoritative guidance on disclosures about offsetting assets and liabilities, the Company is required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting agreement. The Company's derivative instruments are presented as assets and liabilities on a net basis by counterparty, as all counterparty contracts provide for net settlement. No margin or collateral balances are deposited with counterparties, and as such, gross amounts are offset to determine the net amounts presented in the Company's Condensed Consolidated Balance Sheet.

The following tables summarize gross and net information about the Company's commodity derivative instruments:

Offsetting of Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
	(In thousands)		
At September 30, 2016	$ 23,713	$ (14,377)	$ 9,336
At December 31, 2015	155,473	—	155,473

Offsetting of Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet
	(In thousands)		
At September 30, 2016	$ 39,440	$ (14,377)	$ 25,063
At December 31, 2015	—	—	—

6. Property, Plant and Equipment

The following table sets forth the Company's property, plant and equipment:

	September 30, 2016	December 31, 2015
	(In thousands)	
Proved oil and gas properties[(1)]	$5,813,928	$5,655,759
Less: accumulated depreciation, depletion, amortization and impairment	(1,764,979)	(1,428,427)
Proved oil and gas properties, net	4,048,949	4,227,332
Unproved oil and gas properties	624,854	628,642
Other property and equipment	580,171	443,265
Less: accumulated depreciation	(101,301)	(80,997)
Other property and equipment, net	478,870	362,268
Total property, plant and equipment, net	$5,152,673	$5,218,242

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $31.5 million and $30.7 million at September 30, 2016 and December 31, 2015, respectively.

Table of Contents

7. Divestiture

On April 1, 2016, the Company completed the sale of certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations for cash proceeds of $12.3 million, which includes customary post close adjustments, and a $4.0 million 10% secured promissory note due within one year. These sold assets primarily consisted of oil and gas properties in the Company's exploration and production segment and included certain other property and equipment in the Company's midstream segment. For the three and nine months ended September 30, 2016, customary post close adjustments were included in the loss on sale of properties on the Company's Condensed Consolidated Statement of Operations.

For the nine months ended September 30, 2016 and the year ended December 31, 2015, the Company recorded impairment charges of $3.6 million and $9.4 million, respectively, which were included in impairment on the Company's Condensed Consolidated Statement of Operations, to adjust the carrying value of these assets to their estimated fair value, determined based on the expected sales price, less costs to sell. There were no similar charges recorded during the three months ended September 30, 2016 and three and nine months ended September 30, 2015.

8. Long-Term Debt

The Company's long-term debt consists of the following:

	September 30, 2016	December 31, 2015
	(In thousands)	
Senior secured revolving line of credit	$195,000	$138,000
Senior unsecured notes		
7.25% senior unsecured notes due February 1, 2019	54,275	400,000
6.5% senior unsecured notes due November 1, 2021	395,501	400,000
6.875% senior unsecured notes due March 15, 2022	937,080	1,000,000
6.875% senior unsecured notes due January 15, 2023	366,094	400,000
2.625% senior unsecured convertible notes due September 15, 2023	300,000	—
Total principal of senior unsecured notes	2,052,950	2,200,000
Less: unamortized deferred financing costs on senior unsecured notes	(29,500)	(35,416)
Less: unamortized debt discount on senior unsecured convertible notes	(92,877)	—
Total long-term debt	$2,125,573	$2,302,584

Senior secured revolving line of credit. The Company has a senior secured revolving line of credit (the "Credit Facility") of $2,500.0 million as of September 30, 2016, which has a maturity date of April 13, 2020. The Credit Facility is restricted to a borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On February 23, 2016, the lenders under the Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2016, resulting in a decrease in the borrowing base and aggregate elected commitment from $1,525.0 million to $1,150.0 million.

As of September 30, 2016, the Company had $195.0 million of LIBOR loans and $12.3 million of outstanding letters of credit issued under the Credit Facility, resulting in an unused borrowing base committed capacity of $942.7 million. The weighted average interest rate on borrowings outstanding under the Credit Facility was 2.0% and 1.9% as of September 30, 2016 and December 31, 2015, respectively. On a quarterly basis, the Company also pays a 0.375% (as of September 30, 2016) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

The Company was in compliance with the financial covenants of the Credit Facility as of September 30, 2016.

Senior unsecured notes. At September 30, 2016, the Company had $1,753.0 million principal amount of senior unsecured notes outstanding with maturities ranging from February 2019 to January 2023 and coupons ranging from 6.50% to 7.25% (the "Senior Notes"). Prior to certain dates, the Company has the option to redeem some or all of the Senior Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The 7.25% senior unsecured notes due February 2019 (the "2019 Notes") are currently redeemable for cash at a redemption price equal to 101.813% of their principal amount plus accrued and unpaid interest to the redemption date, which redemption price declines to par on February 1, 2017. The Company estimates that the fair value of these redemption options is immaterial at September 30, 2016 and December 31, 2015.

Repurchases of senior unsecured notes. On September 28, 2016, the Company completed its tender offers to repurchase certain outstanding Senior Notes (the “Tender Offers”). As a result of the Tender Offers, the Company repurchased an aggregate principal amount of $362.4 million of its outstanding Senior Notes, consisting of $344.7 million principal amount of its 2019 Notes, $2.2 million principal amount of its 6.5% senior unsecured notes due November 2021 (the “2021 Notes”), $3.4 million principal amount of its 6.875% senior unsecured notes due March 2022 (the “2022 Notes”) and $12.1 million principal amount of its 6.875% senior unsecured notes due January 2023 (the “2023 Notes”), for an aggregate cost of $371.4 million, including accrued interest and fees.

In addition to the Tender Offers, the Company repurchased an aggregate principal amount of $84.6 million of its outstanding Senior Notes, consisting of $1.0 million principal amount of its 2019 Notes, $2.3 million principal amount of its 2021 Notes, $59.5 million principal amount of its 2022 Notes and $21.8 million principal amount of its 2023 Notes, for an aggregate cost of $64.5 million, including accrued interest and fees, during the nine months ended September 30, 2016.

For the three and nine months ended September 30, 2016, the Company recognized a pre-tax loss of $13.8 million and a pre-tax gain of $4.9 million, respectively, related to these repurchases, including the Tender Offers, which were net of unamortized deferred financing costs write-offs of $5.3 million and $6.3 million, respectively, and are reflected in gain (loss) on extinguishment of debt in the Company’s Condensed Consolidated Statement of Operations.

Senior unsecured convertible notes. In September 2016, the Company issued $300.0 million of 2.625% senior unsecured convertible notes due September 2023 (the “Senior Convertible Notes”), which resulted in aggregate net proceeds to the Company of $291.9 million, after deducting underwriting discounts and commissions and estimated offering expenses. The Company used the proceeds from the Senior Convertible Notes to fund the repurchase of certain outstanding Senior Notes through the Tender Offers. The Senior Convertible Notes will mature on September 15, 2023 unless earlier converted in accordance with their terms.

The Company has the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company’s intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. Prior to March 15, 2023, the Senior Convertible Notes will be convertible only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on September 30, 2016 (and only during such calendar quarter), if the last reported sale price of the Company’s common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the “measurement period”) in which the trading price per $1,000 principal amount of the Senior Convertible Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of the Company’s common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events, including certain distributions or a fundamental change. On or after March 15, 2023, the Senior Convertible Notes will be convertible at any time until the second scheduled trading day immediately preceding their September 15, 2023 maturity date. The Senior Convertible Notes will be convertible at an initial conversion rate of 76.3650 shares of the Company’s common stock per $1,000 principal amount of the Senior Convertible Notes, which is equivalent to an initial conversion price of approximately $13.10. The conversion rate will be subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date or a notice of redemption, the Company will increase the conversion rate for a holder who elects to convert its Senior Convertible Notes in connection with such corporate event or redemption in certain circumstances. As of September 30, 2016, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met.

Upon issuance, the Company separately accounted for the liability and equity components of the Senior Convertible Notes in accordance with Accounting Standards Codification 470-20. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the Senior Convertible Notes and the estimated fair value of the liability component was recorded as a debt discount and will be amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 8.97% per annum. The fair value of the Senior Convertible Notes as of the issuance date was estimated at $206.8 million, resulting in a debt discount at inception of $93.2 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the Senior Convertible Notes issuance. This equity component was recorded, net of deferred taxes and issuance costs, in additional paid-in capital and will not be remeasured as long as it continues to meet the conditions for equity classification.

Transaction costs related to the Senior Convertible Notes issuance were allocated to the liability and equity components based on their relative fair values. Issuance costs attributable to the liability component of $5.4 million were recorded in deferred financing costs within long-term debt on the Company's Condensed Consolidated Balance Sheet and are being amortized to interest expense over the term of the Senior Convertible Notes using the effective interest method. Issuance costs attributable to the equity component of $2.4 million were recorded as a charge to additional paid-in capital.

Table of Contents

Interest on the Senior Notes and the Senior Convertible Notes (collectively, the "Notes") is payable semi-annually in arrears. The Notes are guaranteed on a senior unsecured basis by the Company, along with its material subsidiaries (the "Guarantors"), which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors, subject to certain customary release provisions. The indentures governing the Notes contain customary events of default as well as covenants that place restrictions on the Company and certain of its subsidiaries.

Deferred financing costs. At September 30, 2016, the Company had $35.0 million of deferred financing costs related to the Notes and the Credit Facility. Deferred financing costs of $29.5 million related to the Notes are included in long-term debt on the Company's Condensed Consolidated Balance Sheet at September 30, 2016, and are being amortized over the respective terms of the Notes. Deferred financing costs of $5.5 million related to the Credit Facility are included in other assets on the Company's Condensed Consolidated Balance Sheet at September 30, 2016, and are being amortized over the term of the Credit Facility. Amortization of deferred financing costs recorded was $2.1 million and $6.2 million for the three and nine months ended September 30, 2016, respectively, and $1.6 million and $5.0 million for the three and nine months ended September 30, 2015, respectively. These costs are included in interest expense on the Company's Condensed Consolidated Statement of Operations. For the nine months ended September 30, 2016 and 2015, the Company's interest expense also included $1.8 million and $0.5 million, respectively, for unamortized deferred financing costs related to the Credit Facility, which were written off in proportion to the decreases in the borrowing base. No deferred financing costs related to the Credit Facility were written off during the three months ended September 30, 2016 and 2015. Aforementioned, the gain (loss) on extinguishment of debt in the Company's Condensed Consolidated Statement of Operations included unamortized deferred financing costs write-offs of $5.3 million and $6.3 million related to the repurchased Notes for the three and nine months ended September 30, 2016, respectively. No deferred financing costs related to the Notes were written off during the three and nine months ended September 30, 2015.

9. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the nine months ended September 30, 2016:

	(In thousands)
Balance at December 31, 2015	$ 35,812
Liabilities incurred during period	465
Liabilities settled during period[1]	(444)
Accretion expense during period[2]	1,425
Revisions to estimates	571
Balance at September 30, 2016	$ 37,829

(1) Liabilities settled during the nine months ended September 30, 2016 included ARO related to the sold properties (see Note 7 – Divestiture).

(2) Included in depreciation, depletion and amortization on the Company's Condensed Consolidated Statement of Operations.

At September 30, 2016, the current portion of the total ARO balance was approximately $0.7 million and was included in accrued liabilities on the Company's Condensed Consolidated Balance Sheet.

10. Income Taxes

The Company's effective tax rate for the three and nine months ended September 30, 2016 was 33.0% and 34.0%, respectively. The Company's effective tax rate for the three and nine months ended September 30, 2015 was 43.0% and 28.7%, respectively. The effective tax rates for the three and nine months ended September 30, 2016 and the nine months ended September 30, 2015 were lower than the combined federal statutory rate and the statutory rates for the states in which the Company conducts business due to the impact of permanent differences on pre-tax loss for these periods, while the effective tax rate for three months ended September 30, 2015 was higher than the combined federal statutory rate and the statutory rates for the states in which the Company conducts business due to the impact of permanent differences on pre-tax income for the period. The permanent differences were primarily between amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vesting during the three and nine months ended September 30, 2016 and 2015.

While the Company is in an overall deferred tax liability position, the Company had deferred tax assets for its federal and state tax net operating losses and other tax carryforwards recorded in deferred income taxes at September 30, 2016. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. During the nine months ended September 30, 2016, the Company recorded a valuation allowance of $0.8 million and $0.6 million for Montana net operating losses and for federal charitable contribution carryovers, respectively, based on management's assessment that it is more likely than not that these net deferred tax assets will not be realized prior to their expiration due to their short carryover periods, current economic conditions and expectations for the future. Management determined that a valuation allowance was not required for its U.S. federal tax net operating loss carryforwards as they are expected to be fully utilized before their expiration. However, the amount of deferred tax assets considered realizable could be reduced in the future if subjective positive evidence becomes limited by objective negative evidence. Management's estimates of future taxable income are significantly affected by changes in commodity prices, the timing and amount of future production and future operating and capital costs.

At September 30, 2016, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

11. Common Stock

On February 2, 2016, the Company completed a public offering of 39,100,000 shares of its common stock (including 5,100,000 shares issued pursuant to the underwriters' option to purchase additional common stock) at an offering price of $4.685 per share. Net proceeds from the offering were $182.8 million, after deducting underwriting discounts and commissions and offering expenses, of which $0.4 million is included in common stock and $182.4 million is included in additional paid-in capital on the Company's Condensed Consolidated Balance Sheet at September 30, 2016. The Company used the net proceeds for general corporate purposes. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on July 15, 2014.

12. Stock-Based Compensation

Restricted stock awards. The Company has granted restricted stock awards to employees and directors under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the closing sales price of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. For the nine months ended September 30, 2016, the Company assumed annual forfeiture rates by employee group ranging from 0% to 20.0% based on the Company's forfeiture history for this type of award.

During the nine months ended September 30, 2016, employees and non-employee directors of the Company were granted restricted stock awards equal to 3,393,900 shares of common stock with a $5.61 weighted average grant date per share value. Stock-based compensation expense recorded for restricted stock awards for the three and nine months ended September 30, 2016 was $4.8 million and $15.5 million, respectively, and $5.0 million and $16.8 million for the three and nine months ended September 30, 2015, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

Performance share units. The Company has granted performance share units ("PSUs") to officers of the Company under its Amended and Restated 2010 Long Term Incentive Plan. The PSUs are awards of restricted stock units, and each PSU that is earned represents the right to receive one share of the Company's common stock. For the nine months ended September 30, 2016, the Company assumed annual forfeiture rates by employee group ranging from 3.3% to 4.6% based on the Company's forfeiture history for the officer employee groups receiving PSUs.

During the nine months ended September 30, 2016, officers of the Company were granted 910,000 PSUs with a $3.00 weighted average grant date per share value. Stock-based compensation expense recorded for PSUs for the three and nine months ended September 30, 2016 was $1.0 million and $3.2 million, respectively, and $1.0 million and $2.9 million for the three and nine months ended September 30, 2015, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

The Company accounted for these PSUs as equity awards pursuant to the FASB's authoritative guidance for share-based payments. The number of PSUs to be earned is subject to a market condition, which is based on a comparison of the total shareholder return ("TSR") achieved with respect to shares of the Company's common stock against the TSR achieved by a defined peer group at the end of the performance periods. Depending on the Company's TSR performance relative to the defined peer group, award recipients will earn between 0% and 200% of the initial PSUs granted. The grant date fair value for each grant of PSUs is recognized on a straight-line basis over a four-year total performance period. All compensation expense related to the PSUs will be recognized if the requisite performance period is fulfilled, even if the market condition is not achieved.

The aggregate grant date fair value of the market-based awards was determined using a Monte Carlo simulation model, which results in an expected percentage of PSUs earned. The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probabilistic assessment. The key valuation assumptions

Table of Contents

for the Monte Carlo model are the forecast period, initial value, risk-free interest rate, volatility and correlation coefficients. The risk-free interest rate is the U.S. Treasury bond rate on the date of grant that corresponds to the total performance period. The initial value is the average of the volume weighted average prices for the 30 trading days prior to the start of the performance cycle for the Company and each of its peers. Volatility is the standard deviation of the average percentage change in stock price over a historical period for the Company and each of its peers. The correlation coefficients are measures of the strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the PSUs granted during the nine months ended September 30, 2016:

Forecast period (years)	4.00	
Risk-free interest rate	1.25	%
Oasis stock price volatility	59.38	%

For the PSUs granted during the nine months ended September 30, 2016, the Monte Carlo simulation model resulted in approximately 69% of PSUs expected to be earned.

13. Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing the earnings (loss) attributable to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings (loss) per share includes the impact of potentially dilutive non-vested restricted shares and PSUs outstanding during the periods presented, unless their effect is anti-dilutive. There are no adjustments made to the earnings (loss) attributable to common stockholders in the calculation of diluted earnings (loss) per share.

The following is a calculation of the basic and diluted weighted average shares outstanding for the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Basic weighted average common shares outstanding	177,120	137,014	172,360	127,827
Dilution effect of stock awards at end of period	—	—	—	—
Diluted weighted average common shares outstanding	177,120	137,014	172,360	127,827

During the three and nine months ended September 30, 2016 and the nine months ended September 30, 2015, the Company incurred a net loss and therefore the diluted loss per share calculation for those periods excludes the anti-dilutive effect of 5,139,848, 4,935,353 and 2,939,368 unvested stock awards, respectively. In addition, the diluted earnings per share calculation for the three months ended September 30, 2015 excludes the dilutive effect of 2,787,054 unvested stock awards that were anti-dilutive under the treasury stock method.

The Company has the option to settle conversions of its Senior Convertible Notes with cash, shares of common stock or a combination of cash and common stock at its election (see Note 8 – Long-Term Debt). The Company’s intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. As a result, only the amount by which the conversion value exceeds the aggregate principal amount of the notes (conversion spread) is considered in the diluted earnings per share computation under the treasury stock method. As of September 30, 2016, the conversion value did not exceed the principal amount of the notes, and accordingly, there was no impact to diluted earnings per share for the three and nine months ended September 30, 2016.

Table of Contents

14. Business Segment Information

The Company's exploration and production segment is engaged in the acquisition and development of oil and natural gas properties. Revenues for the exploration and production segment are derived from the sale of oil and natural gas production. The Company's well services business segment (OWS) performs services for the Company's oil and natural gas wells operated by OPNA. Revenues for the well services segment are derived from providing well services, product sales and equipment rentals. The Company's midstream services business segment (OMS) performs salt water gathering and disposal and other midstream services for the Company's oil and natural gas wells operated by OPNA. Revenues for the midstream segment are primarily derived from salt water pipeline transport, salt water disposal, fresh water sales and natural gas gathering. The revenues and expenses related to work performed by OWS and OMS for OPNA's working interests are eliminated in consolidation, and only the revenues and expenses related to non-affiliated working interest owners are included in the Company's Condensed Consolidated Statement of Operations. These segments represent the Company's three operating units, each offering different products and services. The Company's corporate activities have been allocated to the supported business segments accordingly.

Table of Contents

Management evaluates the performance of the Company's business segments based on operating income, which is defined as segment operating revenues less operating expenses, including depreciation, depletion and amortization. The following table summarizes financial information for the Company's three business segments for the periods presented:

	Exploration and Production	Well Services	Midstream Services	Eliminations	Consolidated
	(In thousands)				
Three months ended September 30, 2016:					
Revenues from non-affiliates	$158,183	$ 10,641	$8,487	$—	$177,311
Inter-segment revenues	—	11,818	20,790	(32,608)	—
Total revenues	158,183	22,459	29,277	(32,608)	177,311
Operating income (loss)	(41,857)	1,572	16,525	(1,942)	(25,702)
Other income (expense)	(24,476)	5	(460)	—	(24,931)
Income (loss) before income taxes	$(66,333)	$ 1,577	$16,065	$(1,942)	$(50,633)
Three months ended September 30, 2015:					
Revenues from non-affiliates	$175,270	$ 15,381	$6,584	$—	$197,235
Inter-segment revenues	—	33,554	23,228	(56,782)	—
Total revenues	175,270	48,935	29,812	(56,782)	197,235
Operating income (loss)	(38,289)	10,936	18,828	(11,401)	(19,926)
Other income (expense)	67,359	14	—	—	67,373
Income (loss) before income taxes	$29,070	$ 10,950	$18,828	$(11,401)	$47,447
Nine months ended September 30, 2016:					
Revenues from non-affiliates	$434,835	$ 29,459	$22,380	$—	$486,674
Inter-segment revenues	—	45,023	65,650	(110,673)	—
Total revenues	434,835	74,482	88,030	(110,673)	486,674
Operating income (loss)	(175,480)	3,420	49,724	(6,795)	(129,131)
Other income (expense)	(155,595)	42	(462)	—	(156,015)
Income (loss) before income taxes	$(331,075)	$ 3,462	$49,262	$(6,795)	$(285,146)
Nine months ended September 30, 2015:					
Revenues from non-affiliates	$563,239	$ 27,308	$17,121	$—	$607,668
Inter-segment revenues	—	131,220	58,994	(190,214)	—
Total revenues	563,239	158,528	76,115	(190,214)	607,668
Operating income (loss)	(103,065)	29,554	44,083	(31,570)	(60,998)
Other income (expense)	(1,037)	34	(44)	—	(1,047)
Income (loss) before income taxes	$(104,102)	$ 29,588	$44,039	$(31,570)	$(62,045)
At September 30, 2016:					
Property, plant and equipment, net	$4,883,137	$ 50,477	$391,282	$(172,223)	$5,152,673
Total assets[(1)]	5,120,567	53,235	396,682	(172,223)	5,398,261
At December 31, 2015:					
Property, plant and equipment, net	$5,057,311	$ 61,402	$264,956	$(165,427)	$5,218,242
Total assets[(1)(2)]	5,478,439	66,952	269,411	(165,427)	5,649,375

(1) Intercompany receivables (payables) for all segments were reclassified to capital contributions from (distributions to) parent and not included in total assets.

(2)

At December 31, 2015, total assets included assets held for sale of $26.7 million in the exploration and production segment related to the assets sold as of April 1, 2016 (see Note 7 – Divestiture).

Table of Contents

15. Commitments and Contingencies

Included below is a discussion of the Company's various future commitments as of September 30, 2016. The commitments under these arrangements are not recorded in the accompanying Condensed Consolidated Balance Sheet. The amounts disclosed represent undiscounted cash flows on a gross basis, and no inflation elements have been applied.

Lease obligations. The Company's total rental commitments under leases for office space and other property and equipment as of September 30, 2016 were $20.7 million.

Volume commitment agreements. As of September 30, 2016, the Company had certain agreements with an aggregate requirement to deliver or transport a minimum quantity of approximately 43.8 MMBbl of crude oil, 23.0 MMBbl of natural gas liquids and 216.7 Bcf of natural gas, prior to any applicable volume credits, within specified timeframes, all of which are ten years or less. The future commitments under certain agreements cannot be estimated as they are based on fixed differentials relative to WTI under the agreements as compared to the differential relative to WTI for the Williston Basin for the production month. The estimable future commitments under these agreements were approximately $443.1 million as of September 30, 2016.

Purchase agreements. As of September 30, 2016, the Company had certain agreements for the purchase of fresh water with an aggregate future commitment of approximately $38.4 million.

Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, the Company believes that all such matters are without merit and involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material adverse effect on its financial condition, results of operations or cash flows. When the Company determines that a loss is probable of occurring and is reasonably estimable, the Company accrues an undiscounted liability for such contingencies based on its best estimate using information available at the time. The Company discloses contingencies where an adverse outcome may be material, or in the judgment of management, the matter should otherwise be disclosed.

16. Condensed Consolidating Financial Information

The Notes (see Note 8 – Long-Term Debt) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company's immaterial wholly-owned subsidiaries do not guarantee the Notes ("Non-Guarantor Subsidiaries").

The following financial information reflects consolidating financial information of the parent company, Oasis Petroleum Inc. ("Issuer"), and its Guarantors on a combined basis, prepared on the equity basis of accounting. The Non-Guarantor Subsidiaries are immaterial and, therefore, not presented separately. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantors operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantors because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantors.

Table of Contents

Condensed Consolidating Balance Sheet

	September 30, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets				
Cash and cash equivalents	$90	$13,686	$—	$13,776
Accounts receivable – oil and gas revenues	—	103,128	—	103,128
Accounts receivable – joint interest and other	—	77,903	—	77,903
Accounts receivable – affiliates	1,348	347,331	(348,679)	—
Inventory	—	8,513	—	8,513
Prepaid expenses	413	5,680	—	6,093
Derivative instruments	—	9,142	—	9,142
Other current assets	—	4,290	—	4,290
Total current assets	1,851	569,673	(348,679)	222,845
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	6,438,782	—	6,438,782
Other property and equipment	—	580,171	—	580,171
Less: accumulated depreciation, depletion, amortization and impairment	—	(1,866,280)	—	(1,866,280)
Total property, plant and equipment, net	—	5,152,673	—	5,152,673
Investments in and advances to subsidiaries	4,478,149	—	(4,478,149)	—
Derivative instruments	—	194	—	194
Deferred income taxes	205,200	—	(205,200)	—
Other assets	—	22,549	—	22,549
Total assets	$4,685,200	$5,745,089	$(5,032,028)	$5,398,261
LIABILITIES AND EQUITY				
Current liabilities				
Accounts payable	$—	$7,929	$—	$7,929
Accounts payable – affiliates	347,331	1,348	(348,679)	—
Revenues and production taxes payable	—	141,991	—	141,991
Accrued liabilities	27	98,899	—	98,926
Accrued interest payable	19,765	33	—	19,798
Derivative instruments	—	17,308	—	17,308
Advances from joint interest partners	—	5,191	—	5,191
Other current liabilities	—	—	—	—
Total current liabilities	367,123	272,699	(348,679)	291,143
Long-term debt	1,930,573	195,000	—	2,125,573
Deferred income taxes	—	751,402	(205,200)	546,202
Asset retirement obligations	—	37,092	—	37,092
Derivative instruments	—	7,755	—	7,755
Other liabilities	—	2,992	—	2,992
Total liabilities	2,297,696	1,266,940	(553,879)	3,010,757
Stockholders’ equity				
Capital contributions from affiliates	—	3,385,326	(3,385,326)	—
Common stock, $0.01 par value: 450,000,000 shares authorized; 182,038,164 shares issued and 181,186,070 shares	1,779	—	—	1,779

outstanding				
Treasury stock, at cost: 852,094 shares	(15,895)	—	—	(15,895)
Additional paid-in-capital	1,755,427	8,743	(8,743)	1,755,427
Retained earnings	646,193	1,084,080	(1,084,080)	646,193
Total stockholders’ equity	2,387,504	4,478,149	(4,478,149)	2,387,504
Total liabilities and stockholders’ equity	$4,685,200	$5,745,089	$(5,032,028)	$5,398,261

20

Table of Contents

Condensed Consolidating Balance Sheet

	December 31, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets				
Cash and cash equivalents	$777	$8,953	$—	$9,730
Accounts receivable – oil and gas revenues	—	96,495	—	96,495
Accounts receivable – joint interest and other	15	100,899	—	100,914
Accounts receivable – affiliates	1,248	247,488	(248,736)	—
Inventory	—	11,072	—	11,072
Prepaid expenses	278	7,050	—	7,328
Derivative instruments	—	139,697	—	139,697
Other current assets	—	50	—	50
Total current assets	2,318	611,704	(248,736)	365,286
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	6,284,401	—	6,284,401
Other property and equipment	—	443,265	—	443,265
Less: accumulated depreciation, depletion, amortization and impairment	—	(1,509,424)	—	(1,509,424)
Total property, plant and equipment, net	—	5,218,242	—	5,218,242
Assets held for sale	—	26,728	—	26,728
Investments in and advances to subsidiaries	4,573,172	—	(4,573,172)	—
Derivative instruments	—	15,776	—	15,776
Deferred income taxes	205,174	—	(205,174)	—
Other assets	100	23,243	—	23,343
Total assets	$4,780,764	$5,895,693	$(5,027,082)	$5,649,375
LIABILITIES AND EQUITY				
Current liabilities				
Accounts payable	$—	$9,983	$—	$9,983
Accounts payable – affiliates	247,488	1,248	(248,736)	—
Revenue and production taxes payable	—	132,356	—	132,356
Accrued liabilities	10	167,659	—	167,669
Accrued interest payable	49,340	73	—	49,413
Advances from joint interest partners	—	4,647	—	4,647
Other current liabilities	—	6,500	—	6,500
Total current liabilities	296,838	322,466	(248,736)	370,568
Long-term debt	2,164,584	138,000	—	2,302,584
Deferred income taxes	—	813,329	(205,174)	608,155
Asset retirement obligations	—	35,338	—	35,338
Liabilities held for sale	—	10,228	—	10,228
Other liabilities	—	3,160	—	3,160
Total liabilities	2,461,422	1,322,521	(453,910)	3,330,033
Stockholders' equity				
Capital contributions from affiliates	—	3,369,895	(3,369,895)	—
Common stock, $0.01 par value: 300,000,000 shares authorized; 139,583,990 shares issued and 139,076,064 shares	1,376	—	—	1,376

outstanding				
Treasury stock, at cost: 507,926 shares	(13,620)	—	—	(13,620)
Additional paid-in-capital	1,497,065	8,743	(8,743)	1,497,065
Retained earnings	834,521	1,194,534	(1,194,534)	834,521
Total stockholders' equity	2,319,342	4,573,172	(4,573,172)	2,319,342
Total liabilities and stockholders' equity	$4,780,764	$5,895,693	$(5,027,082)	$5,649,375

Table of Contents

Condensed Consolidating Statement of Operations

	Three Months Ended September 30, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 158,183	$ —	$ 158,183
Well services and midstream revenues	—	19,128	—	19,128
Total revenues	—	177,311	—	177,311
Operating expenses				
Lease operating expenses	—	35,696	—	35,696
Well services and midstream operating expenses	—	8,165	—	8,165
Marketing, transportation and gathering expenses	—	8,856	—	8,856
Production taxes	—	14,638	—	14,638
Depreciation, depletion and amortization	—	111,948	—	111,948
Exploration expenses	—	489	—	489
Impairment	—	382	—	382
General and administrative expenses	5,930	16,915	—	22,845
Total operating expenses	5,930	197,089	—	203,019
Gain on sale of properties	—	6	—	6
Operating loss	(5,930)	(19,772)	—	(25,702)
Other income (expense)				
Equity in loss of subsidiaries	(1,140)	—	1,140	—
Net gain on derivative instruments	—	20,847	—	20,847
Interest expense, net of capitalized interest	(29,876)	(1,850)	—	(31,726)
Loss on extinguishment of debt	(13,793)	—	—	(13,793)
Other income (expense)	1	(260)	—	(259)
Total other income (expense)	(44,808)	18,737	1,140	(24,931)
Loss before income taxes	(50,738)	(1,035)	1,140	(50,633)
Income tax benefit (expense)	16,796	(105)	—	16,691
Net loss	$(33,942)	$ (1,140)	$ 1,140	$ (33,942)

Table of Contents

Condensed Consolidating Statement of Operations

	Three Months Ended September 30, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 175,270	$ —	$ 175,270
Well services and midstream revenues	—	21,965	—	21,965
Total revenues	—	197,235	—	197,235
Operating expenses				
Lease operating expenses	—	35,670	—	35,670
Well services and midstream operating expenses	—	10,023	—	10,023
Marketing, transportation and gathering expenses	—	8,465	—	8,465
Production taxes	—	16,676	—	16,676
Depreciation, depletion and amortization	—	123,734	—	123,734
Exploration expenses	—	327	—	327
Impairment	—	80	—	80
General and administrative expenses	5,903	16,455	—	22,358
Total operating expenses	5,903	211,430	—	217,333
Gain on sale of properties	—	172	—	172
Operating loss	(5,903)	(14,023)	—	(19,926)
Other income (expense)				
Equity in earnings of subsidiaries	49,899	—	(49,899)	—
Net gain on derivative instruments	—	103,637	—	103,637
Interest expense, net of capitalized interest	(34,020)	(2,493)	—	(36,513)
Other income	1	248	—	249
Total other income (expense)	15,880	101,392	(49,899)	67,373
Income before income taxes	9,977	87,369	(49,899)	47,447
Income tax benefit (expense)	17,078	(37,470)	—	(20,392)
Net income	$27,055	$ 49,899	$ (49,899)	$ 27,055

Table of Contents

Condensed Consolidating Statement of Operations

	Nine Months Ended September 30, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 434,835	$ —	$ 434,835
Well services and midstream revenues	—	51,839	—	51,839
Total revenues	—	486,674	—	486,674
Operating expenses				
Lease operating expenses	—	98,283	—	98,283
Well services and midstream operating expenses	—	21,429	—	21,429
Marketing, transportation and gathering expenses	—	23,899	—	23,899
Production taxes	—	39,758	—	39,758
Depreciation, depletion and amortization	—	356,885	—	356,885
Exploration expenses	—	1,192	—	1,192
Impairment	—	3,967	—	3,967
General and administrative expenses	19,776	49,311	—	69,087
Total operating expenses	19,776	594,724	—	614,500
Loss on sale of properties	—	(1,305)	—	(1,305)
Operating loss	(19,776)	(109,355)	—	(129,131)
Other income (expense)				
Equity in loss of subsidiaries	(110,454)	—	110,454	—
Net loss on derivative instruments	—	(55,624)	—	(55,624)
Interest expense, net of capitalized interest	(97,898)	(7,546)	—	(105,444)
Gain on extinguishment of debt	4,865	—	—	4,865
Other income	44	144	—	188
Total other income (expense)	(203,443)	(63,026)	110,454	(156,015)
Loss before income taxes	(223,219)	(172,381)	110,454	(285,146)
Income tax benefit	34,891	61,927	—	96,818
Net loss	$(188,328)	$(110,454)	$ 110,454	$ (188,328)

Table of Contents

Condensed Consolidating Statement of Operations

	Nine Months Ended September 30, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 563,239	$ —	$ 563,239
Well services and midstream revenues	—	44,429	—	44,429
Total revenues	—	607,668	—	607,668
Operating expenses				
Lease operating expenses	—	112,556	—	112,556
Well services and midstream operating expenses	—	19,370	—	19,370
Marketing, transportation and gathering expenses	—	23,313	—	23,313
Production taxes	—	53,915	—	53,915
Depreciation, depletion and amortization	—	361,430	—	361,430
Exploration expenses	—	2,252	—	2,252
Rig termination	—	3,895	—	3,895
Impairment	—	24,917	—	24,917
General and administrative expenses	20,847	46,343	—	67,190
Total operating expenses	20,847	647,991	—	668,838
Gain on sale of properties	—	172	—	172
Operating loss	(20,847)	(40,151)	—	(60,998)
Other income (expense)				
Equity in earnings of subsidiaries	28,269	—	(28,269)	—
Net gain on derivative instruments	—	111,285	—	111,285
Interest expense, net of capitalized interest	(103,435)	(9,267)	—	(112,702)
Other income	5	365	—	370
Total other income (expense)	(75,161)	102,383	(28,269)	(1,047)
Income (loss) before income taxes	(96,008)	62,232	(28,269)	(62,045)
Income tax benefit (expense)	51,792	(33,963)	—	17,829
Net income (loss)	$(44,216)	$ 28,269	$ (28,269)	$ (44,216)

Table of Contents

Condensed Consolidating Statement of Cash Flows

	Nine Months Ended September 30, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Cash flows from operating activities:				
Net loss	$(188,328)	$(110,454)	$ 110,454	$(188,328)
Adjustments to reconcile net loss to cash provided by (used in) operating activities:				
Equity in loss of subsidiaries	110,454	—	(110,454)	—
Depreciation, depletion and amortization	—	356,885	—	356,885
Gain on extinguishment of debt	(4,865)	—	—	(4,865)
Loss on sale of properties	—	1,305	—	1,305
Impairment	—	3,967	—	3,967
Deferred income taxes	(34,891)	(61,927)	—	(96,818)
Derivative instruments	—	55,624	—	55,624
Stock-based compensation expenses	18,195	566	—	18,761
Deferred financing costs amortization and other	5,371	4,803	—	10,174
Working capital and other changes:				
Change in accounts receivable	(85)	(88,509)	99,943	11,349
Change in inventory	—	2,559	—	2,559
Change in prepaid expenses	(135)	1,303	—	1,168
Change in other current assets	—	(240)	—	(240)
Change in other assets	100	(248)	—	(148)
Change in accounts payable, interest payable and accrued liabilities	70,285	(12,333)	(99,943)	(41,991)
Change in other current liabilities	—	(6,000)	—	(6,000)
Change in other liabilities	—	17	—	17
Net cash provided by (used in) operating activities	(23,899)	147,318	—	123,419
Cash flows from investing activities:				
Capital expenditures	—	(340,314)	—	(340,314)
Proceeds from sale of properties	—	12,333	—	12,333
Costs related to sale of properties	—	(310)	—	(310)
Derivative settlements	—	115,576	—	115,576
Advances from joint interest partners	—	544	—	544
Net cash used in investing activities	—	(212,171)	—	(212,171)
Cash flows from financing activities:				
Repurchase of senior unsecured notes	(435,907)	—	—	(435,907)
Proceeds from issuance of senior unsecured convertible notes	300,000	—	—	300,000
Proceeds from revolving credit facility	—	835,000	—	835,000
Principal payments on revolving credit facility	—	(778,000)	—	(778,000)
Deferred financing costs	(7,880)	(931)	—	(8,811)
Proceeds from sale of common stock	182,791	—	—	182,791
Purchases of treasury stock	(2,275)	—	—	(2,275)
Investment in / capital contributions from subsidiaries	(13,517)	13,517	—	—
Net cash provided by financing activities	23,212	69,586	—	92,798
Increase (decrease) in cash and cash equivalents	(687)	4,733	—	4,046
Cash and cash equivalents at beginning of period	777	8,953	—	9,730

Cash and cash equivalents at end of period	$ 90	$ 13,686	$ —	$ 13,776

Table of Contents

Condensed Consolidating Statement of Cash Flows

	Nine Months Ended September 30, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Cash flows from operating activities:				
Net income (loss)	$(44,216)	$ 28,269	$ (28,269)	$ (44,216)
Adjustments to reconcile net income (loss) to cash provided by operating activities:				
Equity in earnings of subsidiaries	(28,269)	—	28,269	—
Depreciation, depletion and amortization	—	361,430	—	361,430
Gain on sale of properties	—	(172)	—	(172)
Impairment	—	24,917	—	24,917
Deferred income taxes	(51,792)	33,963	—	(17,829)
Derivative instruments	—	(111,285)	—	(111,285)
Stock-based compensation expenses	19,276	353	—	19,629
Deferred financing costs amortization and other	3,401	4,067	—	7,468
Working capital and other changes:				
Change in accounts receivable	(493)	(22,000)	130,802	108,309
Change in inventory	—	8,425	—	8,425
Change in prepaid expenses	(120)	758	—	638
Change in other current assets	—	5,529	—	5,529
Change in accounts payable, interest payable and accrued liabilities	105,536	(58,867)	(130,802)	(84,133)
Change in other current liabilities	—	1,655	—	1,655
Change in other liabilities	—	(28)	—	(28)
Net cash provided by operating activities	3,323	277,014	—	280,337
Cash flows from investing activities:				
Capital expenditures	—	(740,633)	—	(740,633)
Proceeds from sale of properties	—	78	—	78
Derivative settlements	—	291,436	—	291,436
Advances from joint interest partners	—	(1,239)	—	(1,239)
Net cash used in investing activities	—	(450,358)	—	(450,358)
Cash flows from financing activities:				
Proceeds from revolving credit facility	—	618,000	—	618,000
Principal payments on revolving credit facility	—	(938,000)	—	(938,000)
Deferred financing costs	—	(3,587)	—	(3,587)
Proceeds from sale of common stock	462,833	—	—	462,833
Purchases of treasury stock	(2,771)	—	—	(2,771)
Investment in / capital contributions from subsidiaries	(463,404)	463,404	—	—
Net cash provided by (used in) financing activities	(3,342)	139,817	—	136,475
Decrease in cash and cash equivalents	(19)	(33,527)	—	(33,546)
Cash and cash equivalents at beginning of period	776	45,035	—	45,811
Cash and cash equivalents at end of period	$757	$ 11,508	$ —	$ 12,265

Table of Contents

17. Subsequent Events

The Company has evaluated the period after the balance sheet date, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than as noted below.

Derivative instruments. In October 2016, the Company entered into new swaps and two-way and three-way costless collar options for crude oil and natural gas with weighted average floor prices of $51.73 per barrel and $3.38 per MMBtu, respectively. The commodity contracts included total notional amounts of 2,338,000 barrels, 1,219,000 barrels and 93,000 barrels, which settle in 2017, 2018 and 2019, respectively, based on WTI and 668,000 MMBtu and 62,000 MMBtu, which settle in 2017 and 2018, respectively, based on Henry Hub. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

Credit facility amendment. On October 14, 2016, the Company entered into an amendment to its Credit Facility in connection with the scheduled redetermination of its borrowing base. Following the redetermination, the borrowing base and elected commitments were reaffirmed at $1,150.0 million. The next redetermination of the Company's borrowing base is scheduled for April 1, 2017.

Acquisition. On October 17, 2016, the Company signed a purchase and sale agreement (the "Purchase Agreement") with SM Energy Company to acquire approximately 55,000 net acres in the Williston Basin for approximately $785.0 million (the "Williston Basin Acquisition"). The effective date for the Williston Basin Acquisition is October 1, 2016 and the transaction is expected to close on December 1, 2016. The transaction is subject to customary closing conditions. The Purchase Agreement contains various purchase price adjustments to be calculated as of the closing date. The Company will fund the Williston Basin Acquisition with the proceeds from its October 2016 public equity offering discussed below and borrowings under its Credit Facility. The Williston Basin Acquisition will be accounted for as a business combination.

Sale of common stock. On October 21, 2016, the Company completed a public offering of 55,200,000 shares of its common stock (including 7,200,000 shares issued pursuant to the underwriters' option to purchase additional common stock) at a purchase price to the public of $10.80 per share. Net proceeds from the offering were approximately $584.0 million, after deducting underwriting discounts and commissions and estimated offering expenses. The Company intends to use the net proceeds to fund a portion of the Williston Basin Acquisition. The offering was not conditioned on the consummation of the Williston Basin Acquisition, and if the Williston Basin Acquisition does not close, the net proceeds will be used for general corporate purposes, which may include funding a portion of the Company's 2017 capital budget. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on July 15, 2014.

Table of Contents

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Annual Report"), as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, 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 on Form 10-Q, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed under Part II, Item 1A. "Risk Factors" in our 2015 Annual Report could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- our business strategy;
- estimated future net reserves and present value thereof;
- timing and amount of future production of oil and natural gas;
- drilling and completion of wells;
- estimated inventory of wells remaining to be drilled and completed;
- costs of exploiting and developing our properties and conducting other operations;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating a well services company;
- owning, operating and developing a midstream company;
- infrastructure for salt water disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- property acquisitions, including our recent acquisition of oil and gas properties in the Williston Basin;
- integration and benefits of property acquisitions or the effects of such acquisitions on our cash position and levels of indebtedness;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- our financial strategy, budget, projections, execution of business plan and operating results;
- cash flows and liquidity;
- oil and natural gas realized prices;
- general economic conditions;
- operating environment, including inclement weather conditions;
- effectiveness of risk management activities;
- competition in the oil and natural gas industry;
- counterparty credit risk;
- environmental liabilities;
- governmental regulation and the taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;

- technology;
- uncertainty regarding future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Quarterly Report on Form 10-Q. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report on Form 10-Q are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, weather and environmental conditions, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Quarterly Report on Form 10-Q, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Overview

We are an independent exploration and production ("E&P") company focused on the acquisition and development of unconventional oil and natural gas resources primarily in the North Dakota and Montana regions of the Williston Basin. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity is primarily directed toward projects that we believe can provide us with repeatable successes in the Bakken and Three Forks formations. Oasis Petroleum North America LLC ("OPNA") conducts our domestic oil and natural gas E&P activities. We also operate a well services business through Oasis Well Services LLC ("OWS") and a midstream services business through Oasis Midstream Services LLC ("OMS"), both of which are separate reportable business segments that are complementary to our primary development and production activities. The revenues and expenses related to work performed by OWS and OMS for OPNA's working interests are eliminated in consolidation and, therefore, do not directly contribute to our consolidated results of operations.

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. We built our Williston Basin assets through acquisitions and development activities, which were financed with a combination of capital from private investors, borrowings under our revolving credit facility, cash flows provided by operating activities, proceeds from our senior unsecured notes, proceeds from our public equity offerings, the sale of certain non-core oil and gas properties and cash settlements of derivative contracts. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided an entry into a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives. In addition, the acquisition of non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis.

Due to the geographic concentration of our oil and natural gas properties in the Williston Basin, we believe the primary sources of opportunities, challenges and risks related to our business for both the short and long-term are:

- commodity prices for oil and natural gas;
- transportation capacity;
- availability and cost of services; and
- availability of qualified personnel.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments as well as competition from other sources of energy. Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, as well as market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations, and may fluctuate widely in the future. As a result of sustained low oil prices expected in 2016, we decreased our planned 2016 capital expenditures, excluding acquisitions, as compared to 2015, and we are continuing to concentrate our drilling activities in certain areas that are the most economic in the Williston Basin. Extended periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. We enter into crude oil sales contracts with purchasers who have access to crude oil transportation capacity, utilize derivative financial instruments to manage our commodity price risk and enter into physical delivery contracts to manage our price differentials. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows. Additionally, we sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. Currently, we are flowing approximately 75% of our gross operated oil production through these gathering systems.

Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations. Crude oil produced and sold in the Williston Basin has historically sold at a discount to the NYMEX West Texas Intermediate crude oil index prices ("WTI") due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to oil production in the area increasing to a point that it temporarily surpassed the available pipeline transportation, rail transportation and refining capacity in the area. Expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved our price differentials received at the lease. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. Since the third quarter of 2015, our price differentials have remained less than $5.00 per barrel discount to WTI on a quarterly basis. Even as WTI improved in 2016, our price differentials averaged $4.70 per barrel of oil.

Forward commodity prices and estimates of future production play a significant role in determining impairment of proved oil and natural gas properties. As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to monitor our proved oil and natural gas properties for impairment. For the nine months ended September 30, 2016, we recorded an impairment charge of $3.6 million to further write down our properties held for sale to their fair value, as determined by the sales price on April 1, 2016, less costs to sell. No other proved impairment charges were recorded during the nine months ended September 30, 2016. In addition, the excess of our expected undiscounted future cash flows over the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations has increased to $3,020.0 million as of September 30, 2016, an increase of approximately 139% as compared to an excess of $1,264.8 million at December 31, 2015. The underlying commodity prices embedded in our expected undiscounted cash flows were determined using NYMEX forward strip prices for five years, escalating 3% per year thereafter. Our expected undiscounted estimated cash flows also included a 3% inflation factor applied to the future operating and development costs after five years. If expected future commodity prices decline by approximately 25% as compared to September 30, 2016, holding all other factors constant, the expected undiscounted cash flows may not exceed the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations. As a result, we may recognize additional proved impairment charges in the future, and such impairment charges could exceed $2.3 billion assuming a discount rate of 10%.

Changes in commodity prices may significantly impact our estimates of oil and natural gas reserves, which are estimated and reported as of December 31 of each calendar year. Our estimated net proved reserves at December 31, 2015 were prepared using SEC pricing, calculated as the unweighted arithmetic average first-day-of-the-month prices for the prior twelve months of $50.16 per barrel for oil and $2.63 per MMBtu for natural gas. We expect the year-end 2016 SEC pricing to be lower than the year-end 2015 SEC pricing based on actual year-to-date commodity prices for 2016 and the current forward commodity price curve; therefore, the following sensitivity table is provided to illustrate the estimated impact of this price decrease on our estimated proved reserves, PV-10 and Standardized Measure. In addition to the different price assumptions, the sensitivity case below includes assumed capital and expense reductions we expect to realize at lower commodity prices resulting in an increase in both the proved developed reserves and proved undeveloped reserves based on an extended economic limit. However, the decrease in the forecasted commodity price outweighs the increase in estimated proved reserves yielding a lower PV-10 and Standardized Measure as compared to December 31, 2015. This sensitivity case is only to demonstrate the impact that a lower price and cost environment would have had on estimated proved reserves, PV-10 and Standardized Measure as of December 31, 2015, holding all other factors constant. There is no assurance that these prices or assumed cost savings will actually be achieved. Our estimated net proved reserves, PV-10 and Standardized Measure were determined using prices for oil and natural gas, without giving effect to derivative transactions, which were held constant throughout the life of the properties. The prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

Table of Contents

	Actual at December 31, 2015[(1)]		Sensitivity Case[(2)]	
Oil price (per Bbl)	$	50.16	$	42.55
Natural gas price (per MMBtu)	2.63		2.49	
Capital expenditure reduction	n/a		15%	
Operating expense reduction	n/a		16%	
Estimated proved developed reserves (MMBoe)	147.6		148.1	
Estimated proved undeveloped reserves (MMBoe)	70.7		71.0	
Total estimated proved reserves (MMBoe)	218.2		219.1	
PV-10 (in millions)[(3)]	$	2,022.7	$	1,741.4
Present value of future income taxes discounted at 10% (in millions)	108.4		22.7	
Standardized Measure of discounted future net cash flows (in millions)[(4)]	$	1,914.3	$	1,718.7

(1) The actual reserve estimates at December 31, 2015 were prepared using SEC pricing, calculated as the unweighted arithmetic average first-day-of-the-month prices for the prior twelve months, which was $50.16 per barrel for oil and $2.63 per MMBtu for natural gas for the year ended December 31, 2015.

(2) The sensitivity case prices represent potential SEC pricing based on actual prices for each of the nine months ended September 30, 2016 and forward commodity prices as of September 30, 2016 for the remaining months of 2016.

(3) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable financial measure under accounting principles generally accepted in the United States of America (“GAAP”), because it does not include the effect of income taxes on discounted future net cash flows. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas reserves. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(4) Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows.

Third Quarter 2016 Highlights:

- Average daily production was 48,509 Boe per day during the three months ended September 30, 2016;
-

- We completed and placed on production 17 gross (7.1 net) operated wells in the Williston Basin in the third quarter of 2016;
- As of September 30, 2016, we had 80 gross operated wells waiting on completion;
- For the three months ended September 30, 2016, total capital expenditures were $78.5 million;
- We completed a $300.0 million public offering of senior unsecured convertible notes due 2023 and a $362.4 million tender of existing senior notes;
- At September 30, 2016, we had $13.8 million of cash and cash equivalents and had total liquidity of $956.5 million, including the availability under our revolving credit facility;
- Net cash provided by operating activities was $123.4 million for the three months ended September 30, 2016.
- Adjusted EBITDA, a non-GAAP financial measure, was $104.4 million for the three months ended September 30, 2016. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net loss and net cash provided by operating activities, see “Non-GAAP Financial Measures” below.

Results of Operations

Revenues

Our oil and gas revenues are derived from the sale of oil and natural gas production. These revenues do not include the effects of derivative instruments and may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Our well services and midstream revenues are primarily derived from well services, product sales, equipment rentals, salt water pipeline transport, salt water disposal, fresh water sales and natural gas gathering for third-party working interest owners in OPNA’s operated wells. Intercompany revenues for work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation.

Table of Contents

The following table summarizes our revenues and production data for the periods presented:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
Operating results (in thousands):						
Revenues						
Oil	$148,962	$169,672	$(20,710)	$413,068	$542,049	$(128,981)
Natural gas	9,221	5,598	3,623	21,767	21,190	577
Well services	10,641	15,381	(4,740)	29,459	27,308	2,151
Midstream	8,487	6,584	1,903	22,380	17,121	5,259
Total revenues	$177,311	$197,235	$(19,924)	$486,674	$607,668	$(120,994)
Production data:						
Oil (MBbls)	3,628	4,077	(449)	11,245	12,107	(862)
Natural gas (MMcf)	5,007	3,438	1,569	13,809	9,940	3,869
Oil equivalents (MBoe)	4,463	4,650	(187)	13,547	13,764	(217)
Average daily production (Boe per day)	48,509	50,546	(2,037)	49,440	50,418	(978)
Average sales prices:						
Oil, without derivative settlements (per Bbl)(1)	$40.54	$41.61	$(1.07)	$36.57	$44.77	$(8.20)
Oil, with derivative settlements (per Bbl)(1)(2)	43.79	60.77	(16.98)	46.85	68.84	(21.99)
Natural gas (per Mcf)(3)	1.84	1.63	0.21	1.58	2.13	(0.55)

(1) For both the three and nine months ended September 30, 2016, average sales prices for oil are calculated using total oil revenues, excluding bulk oil sales of $1.9 million, divided by oil production.

(2) Realized prices include gains or losses on cash settlements for commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

(3) Natural gas prices include the value for natural gas and natural gas liquids.

Three months ended September 30, 2016 as compared to three months ended September 30, 2015

Total revenues. Our total revenues decreased $19.9 million, or 10%, to $177.3 million during the three months ended September 30, 2016 as compared to the three months ended September 30, 2015, primarily due to an 11% decrease in oil volumes sold.

Oil and gas revenues. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold decreased by 2,037 Boe per day to 48,509 Boe per day during the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. The decrease in average daily production sold was primarily a result of the natural decline in production in wells that were producing as of September 30, 2015 coupled with the divestiture completed on April 1, 2016 (see Note 7 to our condensed consolidated financial statements), which resulted in a decrease in average daily production of approximately 407 Boe per day during the three months ended September 30, 2016. This decrease was offset by our 39.5 total net well completions in the Williston Basin during the twelve months ended September 30, 2016, which had higher gas to oil ratios resulting in a 46% increase in natural gas production sold. Average oil sales prices, without derivative settlements, decreased by $1.07 per barrel to an average of $40.54 per barrel, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, increased by $0.21 per Mcf to an average of $1.84 per Mcf for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. The lower oil production amounts sold decreased revenues by $18.2 million coupled with a $4.4 million decrease due to lower oil sales prices during the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. This decrease in oil revenues was offset by a $3.6 million increase in gas revenues due to higher natural gas production amounts sold coupled with higher natural gas sales prices during the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. In addition, oil and gas

revenues included $1.9 million of bulk oil sales related to marketing activities during the three months ended September 30, 2016. Extended low commodity prices could result in a significant decrease in our oil and natural gas volumes and revenues in the future.
Well services and midstream revenues. In response to the low commodity price environment, we decreased the pace of our well completions and reduced OWS to one fracturing fleet during the first quarter of 2016. Our well services revenues

Table of Contents

decreased by $4.7 million to $10.6 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015 primarily due to a decrease in well completion activity, offset by an increase in well completion revenues as a result of OWS completing OPNA wells with a higher average third-party working interest during the three months ended September 30, 2016. Midstream revenues increased by $1.9 million to $8.5 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015 primarily due to increased water volumes flowing through our salt water disposal systems and increased natural gas volumes gathered.

Nine months ended September 30, 2016 as compared to nine months ended September 30, 2015

Our total revenues decreased $121.0 million, or 20%, to $486.7 million during the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015, primarily due to lower realized oil and natural gas sales prices. Our average realized prices for oil and natural gas decreased by 18% and 26%, respectively, during the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015.

Oil and gas revenues. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold decreased by 978 Boe per day, or 2%, to 49,440 Boe per day during the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. The decrease in average daily production sold was primarily a result of the decline in production in wells that were producing as of September 30, 2015 coupled with the divestiture completed on April 1, 2016 (see Note 7 to our condensed consolidated financial statements), which resulted in a decrease in average daily production of approximately 427 Boe per day during the nine months ended September 30, 2016. This decrease was offset by our 39.5 total net well completions in the Williston Basin during the twelve months ended September 30, 2016, which had higher gas to oil ratios resulting in a 39% increase in natural gas production sold. Average oil sales prices, without derivatives settlements, decreased by $8.20 per barrel to an average of $36.57 per barrel, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, decreased by $0.55 per Mcf to an average of $1.58 per Mcf for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. The lower oil and natural gas sales prices decreased revenues by $104.8 million, coupled with lower total oil production amounts sold, which decreased revenues by $31.5 million, and offset by higher natural gas production amounts sold, which increased revenues by $6.1 million, during the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. In addition, oil and gas revenues included $1.9 million of bulk oil sales related to marketing activities during the nine months ended September 30, 2016.

Well services and midstream revenues. In response to the low commodity price environment, we decreased the pace of our well completions and reduced OWS to one fracturing fleet during the first quarter of 2016. While our well completion activity decreased, our well services revenues increased $2.2 million to $29.5 million for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015 primarily due to an increase of $4.5 million in well completion revenue as a result of OWS completing OPNA wells with a higher average third-party working interest, offset by a $1.7 million decrease in well completion product sales to third parties as a result of OWS completing all of OPNA’s operated wells. Midstream revenues were $22.4 million for the nine months ended September 30, 2016, which was a $5.3 million increase period over period, primarily due to increased water volumes flowing through our salt water disposal systems and natural gas volumes gathered, offset by decreased fresh water sales.

Table of Contents

Expenses and other income

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	2015	Change	2016	2015	Change
	(In thousands, except per Boe of production)					
Operating expenses:						
Lease operating expenses	$35,696	$35,670	$26	$98,283	$112,556	$(14,273)
Well services and midstream operating expenses	8,165	10,023	(1,858)	21,429	19,370	2,059
Marketing, transportation and gathering expenses	8,856	8,465	391	23,899	23,313	586
Production taxes	14,638	16,676	(2,038)	39,758	53,915	(14,157)
Depreciation, depletion and amortization	111,948	123,734	(11,786)	356,885	361,430	(4,545)
Exploration expenses	489	327	162	1,192	2,252	(1,060)
Rig termination	—	—	—	—	3,895	(3,895)
Impairment	382	80	302	3,967	24,917	(20,950)
General and administrative expenses	22,845	22,358	487	69,087	67,190	1,897
Total operating expenses	203,019	217,333	(14,314)	614,500	668,838	(54,338)
Gain (loss) on sale of properties	6	172	(166)	(1,305)	172	(1,477)
Operating loss	(25,702)	(19,926)	(5,776)	(129,131)	(60,998)	(68,133)
Other income (expense):						
Net gain (loss) on derivative instruments	20,847	103,637	(82,790)	(55,624)	111,285	(166,909)
Interest expense, net of capitalized interest	(31,726)	(36,513)	4,787	(105,444)	(112,702)	7,258
Gain (loss) on extinguishment of debt	(13,793)	—	(13,793)	4,865	—	4,865
Other income (expense)	(259)	249	(508)	188	370	(182)
Total other income (expense)	(24,931)	67,373	(92,304)	(156,015)	(1,047)	(154,968)
Income (loss) before income taxes	(50,633)	47,447	(98,080)	(285,146)	(62,045)	(223,101)
Income tax benefit (expense)	16,691	(20,392)	37,083	96,818	17,829	78,989
Net income (loss)	$(33,942)	$27,055	$(60,997)	$(188,328)	$(44,216)	$(144,112)
Costs and expenses (per Boe of production):						
Lease operating expenses	$8.00	$7.67	$0.33	$7.26	$8.18	$(0.92)
Marketing, transportation and gathering expenses	1.98	1.82	0.16	1.76	1.69	0.07
Production taxes	3.28	3.59	(0.31)	2.93	3.92	(0.99)
Depreciation, depletion and amortization	25.08	26.61	(1.53)	26.35	26.26	0.09
General and administrative expenses	5.12	4.81	0.31	5.10	4.88	0.22

Three months ended September 30, 2016 as compared to three months ended September 30, 2015

Lease operating expenses. Lease operating expenses remained consistent at $35.7 million for both the three months ended September 30, 2016 and 2015, respectively. Lease operating expenses increased from $7.67 per Boe for the three months ended September 30, 2015 to $8.00 per Boe for the three months ended September 30, 2016 primarily due to lower production volumes.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of service costs, cost of goods sold and operating expenses incurred by OWS and OMS. The $1.9 million decrease for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015 was primarily attributable to a $2.9 million decrease in well completion costs as a result of lower activity, offset by an increase in well completion costs as a result of OWS completing OPNA wells with a higher average third-party working interest. This decrease was offset by an increase in midstream operating expenses of $1.0 million during the three months ended

September 30, 2016 as compared to the three months ended September 30, 2015 due to expenses associated with the start up of our natural gas processing plant, which began operating in the third quarter of 2016, offset by a decrease in fresh water purchases.

Marketing, transportation and gathering expenses. The $0.4 million increase in marketing, transportation and gathering expenses for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015 was primarily attributable to $1.9 million in bulk oil purchases, offset by a $0.9 million decrease in our pipeline imbalance and a $0.6 million decrease in oil transportation costs.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 9.3% and 9.5%, respectively, for the three months ended September 30, 2016 and 2015. The production tax rate decreased period over period primarily due to the reduction in the North Dakota oil extraction tax rate, offset by an increased weighting of production in North Dakota, which has a higher average production tax rate as compared to Montana. For the three months ended September 30, 2016 and 2015, the percentage of our total production located in North Dakota was 93% and 87%, respectively. In 2015, North Dakota had a crude oil tax structure based on a 5% production tax and a 6.5% oil extraction tax, resulting in a combined tax rate of 11.5% of crude oil revenues. In 2016, the North Dakota oil extraction tax was reduced to 5%, resulting in a combined tax rate of 10% of crude oil revenues.

Depreciation, depletion and amortization (“DD&A”). DD&A expense decreased $11.8 million to $111.9 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. This decrease in DD&A expense for the three months ended September 30, 2016 was a result of a decrease in the DD&A rate and a decrease in total production, partially offset by additional wells completed during the three months ended September 30, 2016. The DD&A rate for the three months ended September 30, 2016 was $25.08 per Boe compared to $26.61 per Boe for the three months ended September 30, 2015. The decrease in the DD&A rate was primarily due to lower well costs and higher recoverable reserves.

Impairment. For the three months ended September 30, 2016 and 2015, we recorded non-cash impairment charges of $0.2 million and $0.1 million, respectively, for unproved properties due to leases that expired in the period. As a result of periodic assessments of unproved properties not held-by-production, we recorded an additional impairment charge on our unproved oil and natural gas properties of $0.2 million for the three months ended September 30, 2016 related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. For the three months ended September 30, 2015, we did not record similar impairment charges. No impairment charges of proved oil and gas properties were recorded for the three months ended September 30, 2016 and 2015.

General and administrative expenses (“G&A”). Our G&A increased $0.5 million to $22.8 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. E&P G&A increased $0.3 million to $19.2 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. The increase in E&P G&A was primarily due to $1.8 million of bad debt expense, offset by lower compensation expenses due to a decrease in employee headcount. OWS G&A increased $0.2 million primarily due to OWS completing OPNA wells with a higher average third-party working interest during the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. Excluding our intercompany elimination, gross OWS G&A decreased $3.0 million primarily due to lower compensation expenses due to a decrease in employee headcount. Our total company full-time employee headcount decreased to 464 at September 30, 2016 from 562 at September 30, 2015.

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $20.8 million net gain on derivative instruments, including net cash settlement receipts of $11.8 million, for the three months ended September 30, 2016, and a $103.6 million net gain on derivative instruments, including net cash settlement receipts of $78.1 million, for the three months ended September 30, 2015. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Interest expense. Interest expense decreased $4.8 million from $36.5 million for the three months ended September 30, 2015 to $31.7 million for the three months ended September 30, 2016 due to a decrease in interest expense incurred on our senior unsecured notes during the three months ended September 30, 2016. In 2016, we repurchased an aggregate principal amount of $447.0 million of outstanding senior unsecured notes, which resulted in a decrease of $5.6 million in interest expense for the three months ended September 30, 2016. For the three months ended September 30, 2016 and 2015, the weighted average debt outstanding under our revolving credit facility was $84.3 million and $205.9 million, respectively. The weighted average interest rate incurred on the outstanding borrowings under our revolving credit facility was 2.1% and 1.7% for the three months ended September 30, 2016 and September 30, 2015, respectively. Interest capitalized during the three months ended September 30, 2016 and 2015 was $4.4 million and $5.1 million, respectively.

Gain on extinguishment of debt. During the three months ended September 30, 2016, we repurchased an aggregate principal amount of $370.4 million of our outstanding senior unsecured notes for an aggregate cost of $379.0 million, including accrued interest and fees. For the three months ended September 30, 2016, we recognized a pre-tax loss related to the repurchase of $13.8 million, which included unamortized deferred financing costs write-offs of $5.3 million. For the three months ended September 30, 2015, we did not repurchase any portion of our outstanding senior unsecured notes.

Income taxes. The income tax benefit for the three months ended September 30, 2016 was recorded at 33.0% of pre-tax loss, and income tax expense for the three months ended September 30, 2015 was recorded at 43.0% of pre-tax net income. The effective tax rate for three months ended September 30, 2016 was lower than the combined federal statutory rate and the statutory rates for the states in which we conduct business due to the impact of permanent differences on pre-tax loss for the period, while the effective tax rate for three months ended September 30, 2016 was higher than the combined federal statutory rate and the statutory rates for the states in which we conduct business due to the impact of permanent differences on pre-tax income for the period. The permanent differences were primarily between amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vesting during the three months ended September 30, 2016 and 2015 at stock prices lower than the grant date values.

Nine months ended September 30, 2016 as compared to nine months ended September 30, 2015

Lease operating expense. Lease operating expenses decreased $14.3 million to $98.3 million for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. The decrease was primarily due to an increase in salt water disposal volumes being transported on OMS pipelines and injected in OMS salt water disposal wells. Utilizing our own infrastructure for salt water disposal enables us to lower operating costs through increased operational efficiency. Lease operating expenses decreased from $8.18 per Boe for the nine months ended September 30, 2015 to $7.26 per Boe for the nine months ended September 30, 2016.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of service costs, cost of goods sold and operating expenses incurred by OWS and OMS. The $2.1 million increase for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015 was attributable to a $0.5 million increase due to OWS completing OPNA wells with a higher average third-party working interest, offset by lower well completion activity in the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. This increase was coupled with a $1.6 million increase in midstream operating expenses related to an increase in salt water disposal wells, pipelines and the start up of our natural gas processing plant, which began operating in the third quarter of 2016.

Marketing, transportation and gathering expenses. The $0.6 million increase in marketing, transportation and gathering expenses for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015 was primarily attributable to bulk oil purchases of $1.9 million, offset by a $1.6 million decrease in oil transportation costs.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 9.1% and 9.6%, respectively, for the nine months ended September 30, 2016 and 2015. The production tax rate decreased period over period primarily due to the reduction in the North Dakota oil extraction tax rate, partially offset by an increased weighting of production in North Dakota, which has a higher average production tax rate as compared to Montana. For the nine months ended September 30, 2016 and 2015, the percentage of our total production located in North Dakota was 91% and 87%, respectively. In 2015, North Dakota had a crude oil tax structure based on a 5% production tax and a 6.5% oil extraction tax, resulting in a combined tax rate of 11.5% of crude oil revenues. In 2016, the North Dakota oil extraction tax was reduced to 5%, resulting in a combined tax rate of 10% of crude oil revenues.

Depreciation, depletion, and amortization. DD&A expense decreased $4.5 million to $356.9 million for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. The decrease in DD&A expense for the nine months ended September 30, 2016 was a result of a decrease in the DD&A rate and a decrease in total production, partially offset by additional wells completed during the nine months ended September 30, 2016. The DD&A rate for the nine months ended September 30, 2016 was $26.35 per Boe compared to $26.26 per Boe for the nine months ended September 30, 2015. The decrease in the DD&A rate was primarily due to lower well costs and higher recoverable reserves.

Impairment. During the nine months ended September 30, 2016, we recorded an impairment charge of $3.6 million to adjust the carrying value of our properties held for sale during the first quarter of 2016 to their estimated fair value, determined based on the expected sales price, less costs to sell. No impairment charges of proved oil and gas properties were recorded for the nine months ended September 30, 2015. For the nine months ended September 30, 2016 and 2015, we recorded non-cash impairment charges of $0.2 million and $8.5 million, respectively, for unproved properties due to leases that expired during the period. As a result of periodic assessments of unproved properties not held-by-production, we recorded additional impairment charges of $0.2 million and $16.4 million for the nine months ended September 30, 2016 and 2015, respectively, related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. During the year ended December 31, 2015, we recorded similar non-cash impairment charges of $13.4 million related to leases that expired during the nine months ended September 30, 2016 as a result of periodic assessments of unproved properties. Consequently, lower impairment charges for unproved properties were recorded during the nine months ended September 30, 2016 as most leases that expired during the period had been previously impaired.

General and administrative expenses. Our G&A expenses increased $1.9 million for the nine months ended September 30, 2016 from $67.2 million for the nine months ended September 30, 2015. OWS G&A increased by $4.9 million primarily due to OWS completing OPNA wells with a higher average third-party working interest in the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. Excluding our intercompany elimination, gross OWS G&A decreased $8.4 million. E&P G&A was $58.0 million and $61.0 million for the nine months ended September 30, 2016 and 2015, respectively. These decreases in gross OWS and E&P G&A were primarily due to lower compensation expenses due to a decrease in employee headcount. Our total company full-time employee headcount decreased to 464 at September 30, 2016 from 562 at September 30, 2015.

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $55.6 million net loss on derivative instruments, including net cash settlement receipts of $115.6 million, for the nine months ended September 30, 2016, and a $111.3 million net gain on derivative instruments, including net cash settlement receipts of $291.4 million for the nine months ended September 30, 2015. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Interest expense. Interest expense decreased $7.3 million to $105.4 million for the nine months ended September 30, 2016 as compared to the nine months ended September 30, 2015. The decrease was primarily the result of a decrease in the interest expense incurred on our senior unsecured notes during the nine months ended September 30, 2016. In 2016, we repurchased an aggregate principal amount of $447.0 million of outstanding senior unsecured notes, which resulted in a decrease of $7.4 million in interest expense for the nine months ended September 30, 2016. For the nine months ended September 30, 2016 and 2015, the weighted average debt outstanding under our revolving credit facility was $91.2 million and $280.7 million, respectively, and the weighted average interest rate incurred on the outstanding borrowings was 2.0% and 1.8%, respectively. Interest capitalized during the nine months ended September 30, 2016 and 2015 was $13.7 million and $13.8 million, respectively.

Gain on extinguishment of debt. During the nine months ended September 30, 2016, we repurchased an aggregate principal amount of $447.0 million of our outstanding senior unsecured notes for an aggregate cost of $435.9 million, including accrued interest and fees. For the nine months ended September 30, 2016, we recognized a pre-tax gain related to the repurchase of $4.9 million, which included unamortized deferred financing costs write-offs of $6.3 million. During the nine months ended September 30, 2015, we did not repurchase any portion of our outstanding senior unsecured notes.

Income taxes. Income tax benefit for the nine months ended September 30, 2016 and 2015 was recorded at 34.0% and 28.7% of pre-tax loss, respectively. The effective tax rates for both periods were lower than the combined federal statutory rate and the statutory rates for the states in which we conduct business due to the impact of permanent differences on our pre-tax loss. The permanent differences were primarily for compensation amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vesting during the nine months ended September 30, 2016 and 2015 at stock prices lower than the grant date values. In addition, during the nine months ended September 30, 2016, we recorded a valuation allowance of $0.8 million and $0.6 million for Montana net operating losses and federal charitable contribution carryovers, respectively, based on management's assessment that it is more likely than not that these net deferred tax assets will not be realized prior to their expiration due to their short carryover periods, current economic conditions and expectations for the future.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report have been proceeds from our senior unsecured notes, borrowings under our revolving credit facility, proceeds from public equity offerings, cash flows from operations, the sale of certain non-core oil and gas properties and cash settlements of derivative contracts. Our primary uses of capital have been for the acquisition and development of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings and potential asset monetizations, in order to enhance liquidity and decrease leverage. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Our cash flows for the nine months ended September 30, 2016 and 2015 are presented below:

	Nine Months Ended September 30,	
	2016	2015
	(In thousands)	
Net cash provided by operating activities	$123,419	$280,337
Net cash used in investing activities	(212,171)	(450,358)
Net cash provided by financing activities	92,798	136,475
Increase (decrease) in cash and cash equivalents	$4,046	$(33,546)

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in oil and natural gas prices on a portion of our production, thereby mitigating our exposure to oil and natural gas price declines, but these transactions may also limit our cash flow in periods of rising oil and natural gas prices. Prices for oil have declined significantly since mid-2014, which has substantially decreased our cash flows provided by operating activities. The decline in operating cash flows caused by lower oil prices is partially offset by cash flows from our derivative contracts. For additional information on the impact of changing prices on our financial position, see Item 3. “Quantitative and Qualitative Disclosures About Market Risk” below.

On February 2, 2016, we completed a public equity offering resulting in net proceeds of $182.8 million, after deducting underwriting discounts and commissions and offering expenses, which we used for general corporate purposes.

In September 2016, we issued $300.0 million of 2.625% senior unsecured convertible notes due September 15, 2023 (the “Senior Convertible Notes”), which resulted in aggregate net proceeds to us of $291.9 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we used to fund the tender offers to repurchase certain outstanding Senior Notes (as defined below) (the “Tender Offers”). As a result of the Tender Offers, we repurchased an aggregate principal amount of $362.4 million of our outstanding Senior Notes, for an aggregate cost of $371.4 million, including accrued interest and fees.

On October 21, 2016, we completed a public equity offering resulting in net proceeds of $584.0 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we plan to use to fund a portion the acquisition of approximately 55,000 net acres in the Williston Basin for approximately $785.0 million (the “Williston Basin Acquisition”). The effective date for the Williston Basin Acquisition is October 1, 2016 and the transaction is expected to close on December 1, 2016.

Our existing revolving credit facility provides additional liquidity, with a current borrowing base and elected commitment amount of $1,150.0 million. The next redetermination of the borrowing base is scheduled for April 1, 2017.

We believe we have adequate liquidity to fund remaining 2016 capital expenditures and to meet our near-term future obligations, including the Williston Basin Acquisition.

Cash flows provided by operating activities

Net cash provided by operating activities was $123.4 million and $280.3 million for the nine months ended September 30, 2016 and 2015, respectively. The change in cash flows from operating activities for the period ended September 30, 2016 as compared to 2015 was primarily the result of lower realized oil and natural gas sales prices.

Working capital. Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and acquisitions, and the impact of our outstanding derivative instruments. We had a working capital deficit of $68.3 million at September 30, 2016 due to decreases in our current assets, primarily due to the impact of increases in the forward commodity price curve on our short-term derivative instruments. As of September 30, 2016, we had $956.5 million of liquidity available, including $13.8 million in cash and cash equivalents and $942.7 million of unused borrowing base committed capacity available under our revolving credit facility. At September 30, 2015, we had a working capital deficit of $52.3 million.

Cash flows used in investing activities

Net cash used in investing activities was $212.2 million and $450.4 million during the nine months ended September 30, 2016 and 2015, respectively. Net cash used in investing activities during the nine months ended September 30, 2016 was primarily attributable to $340.3 million in capital expenditures primarily for drilling and development costs, partially offset by $115.6 million of derivative settlements received as a result of lower commodity prices and $12.3 million for proceeds from the

Table of Contents

sale of certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations. Net cash used in investing activities during the nine months ended September 30, 2015 was primarily attributable to $740.6 million in capital expenditures primarily for drilling and development costs, partially offset by $291.4 million of derivative settlements received as a result of lower crude oil pricing.

Our capital expenditures are summarized in the following table:

	Nine Months Ended September 30, 2016
	(In thousands)
Capital expenditures:	
E&P	$ 152,192
OMS	129,966
OWS	679
Other capital expenditures(1)	14,859
Total capital expenditures(2)	$ 297,696

(1) Other capital expenditures include such items as administrative capital and capitalized interest.

(2) Capital expenditures reflected in the table above differ from the amounts shown in the statement of cash flows in our condensed consolidated financial statements because amounts reflected in the table above include changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis.

Our total 2016 capital expenditure budget, excluding the Williston Basin Acquisition, is $400 million, which includes $340 million for E&P capital expenditures and $60 million for non-E&P capital expenditures, including OWS, administrative capital and capitalized interest. Our planned E&P capital expenditures include $200 million of drilling and completion capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS and OMS) and $140 million of OMS capital expenditures (including Wild Basin infrastructure). While we have budgeted $400 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. Additionally, if we complete the Williston Basin Acquisition or acquire additional acreage, our capital expenditures will be higher than budgeted. We believe that cash on hand, cash flows from operating activities, proceeds from our public equity offering, proceeds from cash settlements under our derivative contracts and availability under our revolving credit facility should be sufficient to fund our 2016 capital expenditure budget and the Williston Basin Acquisition. However, because the operated wells funded by our 2016 drilling plan represent only a small percentage of our potential drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of potential drilling locations should we elect to do so.

Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil prices remain low for an extended period of time or continue to decline, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control. We actively review acquisition opportunities on an ongoing basis. Our ability to make significant acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all.

Cash flows provided by financing activities

Net cash provided by financing activities was $92.8 million and $136.5 million for the nine months ended September 30, 2016 and 2015, respectively. For the nine months ended September 30, 2016, cash provided by financing activities was primarily due to proceeds from the borrowings under our revolving credit facility and net proceeds from the issuance of our senior unsecured convertible notes and common stock, partially offset by principal payments on our revolving credit facility and the repurchase of a portion of our outstanding senior unsecured notes. Net cash provided by financing activities during the nine months ended September 30, 2015 was primarily due to net proceeds from the issuance of our common stock and proceeds from borrowings under our revolving credit facility, partially offset by principal payments on our revolving credit facility. For both the nine months ended September 30, 2016 and 2015, cash was used in financing activities for the purchases of treasury stock for shares that employees surrendered back to us to pay tax withholdings upon the vesting of restricted stock awards.

Sale of common stock. On February 2, 2016, we completed a public offering of 39,100,000 shares of our common stock at an offering price of $4.685 per share. We used the net proceeds from the offering of $182.8 million, after deducting underwriting discounts and commissions and offering expenses, for general corporate purposes.

On October 21, 2016, we completed a public offering of 55,200,000 shares of our common stock (including 7,200,000 shares issued pursuant to the underwriters' option to purchase additional common stock) at a purchase price to the public of $10.80 per share. We plan to use the net proceeds of $584.0 million, after deducting underwriting discounts and commissions and estimated offering expenses, to fund a portion of the Williston Basin Acquisition. The effective date for the Williston Basin Acquisition is October 1, 2016 and the transaction is expected to close on December 1, 2016.

Senior secured revolving line of credit. We have a revolving credit facility (the "Credit Facility") with an overall senior secured line of credit of $2,500.0 million as of September 30, 2016. The Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. The maturity date of the Credit Facility is April 13, 2020, provided that the 7.25% senior unsecured notes due February 2019 (the "2019 Notes") are retired or refinanced 90 days prior to their maturity date. On February 23, 2016, the lenders under the Credit Facility (the "Lenders") completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2016, resulting in a decrease in the borrowing base and aggregate elected commitment from $1,525.0 million to $1,150.0 million. On October 14, 2016, the borrowing base and aggregate elected commitment were reaffirmed at $1,150.0 million as a result of the semi-annual redetermination of the borrowing base scheduled for October 1, 2016. The next redetermination of the borrowing base is scheduled for April 1, 2017.

At September 30, 2016, we had $195.0 million of borrowings at a weighted average interest rate of 2.0% and $12.3 million of outstanding letters of credit issued under the Credit Facility. At September 30, 2016, we had an unused borrowing base committed capacity of $942.7 million.

The Credit Facility contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;
- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on our assets and our subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;
- a provision limiting oil and natural gas derivative financial instruments;
- a requirement that we maintain a ratio of consolidated EBITDAX (as defined in the Credit Facility) to consolidated Interest Expense (as defined in the Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter; and
- a requirement that we maintain a Current Ratio (as defined in the Credit Facility) of consolidated current assets (including unused borrowing base committed capacity and with exclusions as described in the Credit Facility) to consolidated current liabilities (with exclusions as described in the Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Credit Facility contains customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable. We were in compliance with the financial covenants of the Credit Facility at September 30, 2016. At September 30, 2016, our consolidated EBITDAX was $546.1 million and our consolidated Interest Expense was $150.7 million, resulting in a ratio of 3.6 as compared to a minimum required ratio of 2.5. In addition, as of September 30, 2016, our consolidated current assets and consolidated current liabilities (as described above) were $1,156.4 million and $273.8 million, respectively, resulting in a Current Ratio of 4.2 as compared to a minimum required ratio of 1.0. Given the extended decline in commodity prices, we continue to closely monitor our financial covenants and do not anticipate a covenant violation in the next twelve months.

Senior unsecured notes. At September 30, 2016, our long-term debt includes outstanding obligations of $1,753.0 million for senior unsecured notes (the “Senior Notes”), including $54.3 million of the 2019 Notes, $395.5 million of the 6.5% senior unsecured notes due November 2021 (the “2021 Notes”), $937.1 million of the 6.875% senior unsecured notes due March 2022 (the “2022 Notes”) and $366.1 million of the 6.875% senior unsecured notes due January 2023 (the “2023 Notes”).

Table of Contents

Prior to certain dates, we have the option to redeem some or all of the Senior Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The 2019 Notes are currently redeemable for cash at a redemption price equal to 101.813% of their principal amount plus accrued and unpaid interest to the redemption date, which redemption price declines to par on February 1, 2017. We may from time to time seek to retire or purchase our outstanding Senior Notes 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.

Repurchases of senior unsecured notes. As a result of the Tender Offers, we repurchased an aggregate principal amount of $362.4 million of the outstanding Senior Notes, consisting of $344.7 million principal amount of the 2019 Notes, $2.2 million principal amount of the 2021 Notes, $3.4 million principal amount of the 2022 Notes and $12.1 million principal amount of the 2023 Notes, for an aggregate cost of $371.4 million, including accrued interest and fees.

In addition to the Tender Offers, we repurchased an aggregate principal amount of $84.6 million of the outstanding Senior Notes, consisting of $1.0 million principal amount of the 2019 Notes, $2.3 million principal amount of the 2021 Notes, $59.5 million principal amount of the 2022 Notes and $21.8 million principal amount of the 2023 Notes, for an aggregate cost of $64.5 million, including accrued interest and fees, during the nine months ended September 30, 2016.

For the three and nine months ended September 30, 2016, we recognized a pre-tax loss of $13.8 million and a pre-tax gain of $4.9 million, respectively, related to these repurchases, including the Tender Offers, which were net of unamortized deferred financing costs write-offs of $5.3 million and $6.3 million, respectively, and are reflected in gain (loss) on extinguishment of debt in the our Condensed Consolidated Statement of Operations.

Senior unsecured convertible notes. In September 2016, we issued $300.0 million of 2.625% Senior Convertible Notes due September 2023, which resulted in aggregate net proceeds to us of $291.9 million, after deducting underwriting discounts and commissions and estimated offering expenses. We used the proceeds from the Senior Convertible Notes to fund the repurchase of Senior Notes in the Tender Offers. The Senior Convertible Notes will mature on September 15, 2023 unless earlier converted in accordance with their terms.

We have the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at out election. Our intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. Prior to March 15, 2023, the Senior Convertible Notes will be convertible only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on September 30, 2016 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the “measurement period”) in which the trading price per $1,000 principal amount of the Senior Convertible Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after March 15, 2023, the Senior Convertible Notes will be convertible at any time until the second scheduled trading day immediately preceding the September 15, 2023 maturity date. The Senior Convertible Notes will be convertible at an initial conversion rate of 76.3650 shares of our common stock per $1,000 principal amount of the notes, which is equivalent to an initial conversion price of approximately $13.10. The conversion rate will be subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date or a notice of redemption, we will increase the conversion rate for a holder who elects to convert the Senior Convertible Notes in connection with such corporate event or redemption in certain circumstances. As of September 30, 2016, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met.

Interest on the Senior Notes and the Senior Convertible Notes (collectively, the “Notes”) is payable semi-annually in arrears. The Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The indentures governing the Notes restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when our Notes are rated investment grade by both Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Table of Contents

Obligations and commitments

We have the following contractual obligations and commitments as of September 30, 2016:

Contractual obligations	Payments due by period				
	Total	Within 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Senior unsecured notes[1]	$2,052,950	$—	$54,275	$395,501	$1,603,174
Interest payments on senior unsecured notes[1]	724,179	127,004	252,254	246,352	98,569
Borrowings under revolving credit facility[1]	195,000	—	—	195,000	—
Interest payments on borrowings under revolving credit facility[1]	237	237	—	—	—
Asset retirement obligations[2]	37,829	737	1,529	641	34,922
Operating leases[3]	20,696	5,712	9,992	4,992	—
Volume commitment agreements[3]	443,101	27,687	103,426	110,868	201,120
Purchase agreements[3]	38,440	4,298	17,042	16,700	400
Total contractual cash obligations	$3,512,432	$165,675	$438,518	$970,054	$1,938,185

(1) See Note 8 to our unaudited condensed consolidated financial statements for a description of our senior unsecured notes, revolving credit facility and related interest payments. As of September 30, 2016, we had $195.0 million of borrowings and $12.3 million of outstanding letters of credit issued under our revolving credit facility.

(2) Amounts represent our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 9 to our unaudited condensed consolidated financial statements.

(3) See Note 15 to our unaudited condensed consolidated financial statements for a description of our operating leases, volume commitment agreements and purchase agreements.

Non-GAAP Financial Measures

Cash Interest, Adjusted EBITDA, Free Cash Flow, Adjusted Net Income (Loss) and Adjusted Diluted Earnings (Loss) Per Share are supplemental non-GAAP financial measures that are used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. These non-GAAP measures should not be considered in isolation or as a substitute for interest expense, net income (loss), operating income (loss), net cash provided by (used in) operating activities, earnings (loss) per share or any other measures prepared under GAAP. Because Cash Interest, Adjusted EBITDA, Free Cash Flow, Adjusted Net Income (Loss) and Adjusted Diluted Earnings (Loss) Per Share exclude some but not all items that affect net income (loss) and may vary among companies, the amounts presented may not be comparable to similar metrics of other companies.

Table of Contents

Cash Interest

We define Cash Interest as interest expense plus capitalized interest less amortization and write-offs of deferred financing costs and debt discounts included in interest expense. Cash Interest is not a measure of interest expense as determined by GAAP. Management believes that the presentation of Cash Interest provides useful additional information to investors and analysts for assessing the interest charges incurred on our debt, excluding non-cash amortization, and our ability to maintain compliance with our debt covenants.

The following table presents a reconciliation of the GAAP financial measure of interest expense to the non-GAAP financial measure of Cash Interest for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Interest expense	$31,726	$36,513	$105,444	$112,702
Capitalized interest	4,380	5,054	13,683	13,830
Amortization of deferred financing costs	(2,095)	(1,570)	(8,042)	(5,527)
Amortization of debt discount	(300)	—	(300)	—
Cash Interest	$33,711	$39,997	$110,785	$121,005

Adjusted EBITDA and Free Cash Flow

We define Adjusted EBITDA as earnings (loss) before interest expense, income taxes, DD&A, exploration expenses and other similar non-cash or non-recurring charges. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Management believes that the presentation of Adjusted EBITDA provides useful additional information to investors and analysts for assessing our results of operations, financial performance and our ability to generate cash from our business operations.

We define Free Cash Flow as Adjusted EBITDA less Cash Interest and capital expenditures, excluding capitalized interest. Free Cash Flow is not a measure of net income (loss) or cash flows as determined by GAAP. Management believes that the presentation of Free Cash Flow provides useful additional information to investors and analysts for assessing our financial performance as compared to our peers and our ability to generate cash from our business operations after interest and capital spending. In addition, Free Cash Flow excludes changes in operating assets and liabilities that relate to the timing of cash receipts and disbursements, which we may not control, and changes in operating assets and liabilities may not relate to the period in which the operating activities occurred.

Table of Contents

The following table presents reconciliations of the GAAP financial measures of net income (loss) and net cash provided by (used in) operating activities to the non-GAAP financial measures of Adjusted EBITDA and Free Cash Flow for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Net income (loss)	$(33,942)	$27,055	$(188,328)	$(44,216)
(Gain) loss on sale of properties	(6)	(172)	1,305	(172)
(Gain) loss on extinguishment of debt	13,793	—	(4,865)	—
Net (gain) loss on derivative instruments	(20,847)	(103,637)	55,624	(111,285)
Derivative settlements[1]	11,786	78,100	115,576	291,436
Interest expense, net of capitalized interest	31,726	36,513	105,444	112,702
Depreciation, depletion and amortization	111,948	123,734	356,885	361,430
Impairment	382	80	3,967	24,917
Rig termination	—	—	—	3,895
Exploration expenses	489	327	1,192	2,252
Stock-based compensation expenses	5,782	5,966	18,761	19,629
Income tax (benefit) expense	(16,691)	20,392	(96,818)	(17,829)
Other non-cash adjustments	(26)	883	697	782
Adjusted EBITDA	104,394	189,241	369,440	643,541
Cash Interest	(33,711)	(39,997)	(110,785)	(121,005)
Capital expenditures[2]	(78,453)	(78,053)	(297,696)	(519,566)
Capitalized interest	4,380	5,054	13,683	13,830
Free Cash Flow	$(3,390)	$76,245	$(25,358)	$16,800
Net cash provided by operating activities	$32,018	$50,451	$123,419	$280,337
Derivative settlements[1]	11,786	78,100	115,576	291,436
Interest expense, net of capitalized interest	31,726	36,513	105,444	112,702
Rig termination	—	—	—	3,895
Exploration expenses	489	327	1,192	2,252
Deferred financing costs amortization and other	(3,622)	(2,409)	(10,174)	(7,468)
Changes in working capital	32,023	25,376	33,286	(40,395)
Other non-cash adjustments	(26)	883	697	782
Adjusted EBITDA	104,394	189,241	369,440	643,541
Cash Interest	(33,711)	(39,997)	(110,785)	(121,005)
Capital expenditures[2]	(78,453)	(78,053)	(297,696)	(519,566)
Capitalized interest	4,380	5,054	13,683	13,830
Free Cash Flow	$(3,390)	$76,245	$(25,358)	$16,800

(1) Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

(2) Capital expenditures reflected in the table above differ from the amounts shown in the statement of cash flows in our condensed consolidated financial statements because amounts reflected in the table above include changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis.

45

Table of Contents

The following tables present reconciliations of the GAAP financial measure of income (loss) before income taxes to the non-GAAP financial measure of Adjusted EBITDA for our three reportable business segments on a gross basis for the periods presented:

Exploration and Production

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	(In thousands)			
Income (loss) before income taxes	$(66,333)	$29,070	$(331,075)	$(104,102)
(Gain) loss on sale of properties	(6)	(172)	1,663	(172)
(Gain) loss on extinguishment of debt	13,793			