Oasis Petroleum Inc.
Form 10-Q
November 06, 2018
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, 2018
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	80-0554627
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1001 Fannin Street, Suite 1500 Houston, Texas	77002
(Address of principal executive offices)	(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 every Interactive Data File required to be submitted 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 such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý	Accelerated filer ¨
Non-accelerated filer o	Smaller reporting company ¨
	Emerging growth company ¨

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

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

Number of shares of the registrant's common stock outstanding at November 1, 2018: 318,434,087 shares.

Table of Contents

OASIS PETROLEUM INC.
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2018
TABLE OF CONTENTS

Table of Contents

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

	September 30, 2018	December 31, 2017
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 16,892	$ 16,720
Accounts receivable, net	428,184	363,580
Inventory	31,409	19,367
Prepaid expenses	6,444	7,631
Derivative instruments	—	344
Intangible assets, net	375	—
Other current assets	192	193
Total current assets	483,496	407,835
Property, plant and equipment		
Oil and gas properties (successful efforts method)	8,671,144	7,838,955
Other property and equipment	1,088,781	868,746
Less: accumulated depreciation, depletion, amortization and impairment	(2,859,788)	(2,534,215)
Total property, plant and equipment, net	6,900,137	6,173,486
Derivative instruments	—	9
Long-term inventory	12,610	12,200
Other assets	20,188	21,600
Total assets	$ 7,416,431	$ 6,615,130
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 17,206	$ 13,370
Revenues and production taxes payable	287,333	213,995
Accrued liabilities	307,526	236,480
Accrued interest payable	20,574	38,963
Derivative instruments	180,129	115,716
Advances from joint interest partners	3,878	4,916
Other current liabilities	40	40
Total current liabilities	816,686	623,480
Long-term debt	2,633,009	2,097,606
Deferred income taxes	230,504	305,921
Asset retirement obligations	51,357	48,511
Derivative instruments	33,017	19,851
Other liabilities	7,775	6,182
Total liabilities	3,772,348	3,101,551
Commitments and contingencies (Note 17)		
Stockholders' equity		
Common stock, $0.01 par value: 900,000,000 and 450,000,000 shares authorized at September 30, 2018 and December 31, 2017, respectively; 320,507,783 shares issued and 318,419,144 shares outstanding at September 30, 2018 and 270,627,014 shares	3,157	2,668

issued and 269,295,466 shares outstanding at December 31, 2017		
Treasury stock, at cost: 2,088,639 and 1,331,548 shares at September 30, 2018 and December 31, 2017, respectively	(28,985)	(22,179)
Additional paid-in capital	3,070,642	2,677,217
Retained earnings	460,712	717,985
Oasis share of stockholders' equity	3,505,526	3,375,691
Non-controlling interests	138,557	137,888
Total stockholders' equity	3,644,083	3,513,579
Total liabilities and stockholders' equity	$ 7,416,431	$ 6,615,130

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

1

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$452,643	$248,648	$1,212,235	$704,533
Purchased oil and gas sales	46,356	21,195	121,971	56,917
Midstream revenues	31,187	18,767	88,451	48,939
Well services revenues	16,262	16,138	46,344	33,566
Total revenues	546,448	304,748	1,469,001	843,955
Operating expenses				
Lease operating expenses	48,534	45,334	137,456	133,871
Midstream operating expenses	8,652	4,301	24,325	10,891
Well services operating expenses	11,405	10,288	32,352	23,858
Marketing, transportation and gathering expenses	30,713	15,028	74,559	38,018
Purchased oil and gas expenses	46,088	21,701	121,251	57,683
Production taxes	38,722	21,052	103,748	60,322
Depreciation, depletion and amortization	162,984	132,289	465,819	384,246
Exploration expenses	22,315	854	23,701	4,010
Impairment	—	139	384,228	6,021
General and administrative expenses	34,859	21,368	91,029	67,170
Total operating expenses	404,272	272,354	1,458,468	786,090
Gain on sale of properties	36,869	—	38,823	—
Operating income	179,045	32,394	49,356	57,865
Other income (expense)				
Net gain (loss) on derivative instruments	(48,544)	(54,310)	(239,945)	52,297
Interest expense, net of capitalized interest	(39,560)	(37,389)	(117,616)	(110,548)
Loss on extinguishment of debt	(47)	—	(13,698)	—
Other income (expense)	111	(605)	146	(755)
Total other expense	(88,040)	(92,304)	(371,113)	(59,006)
Income (loss) before income taxes	91,005	(59,910)	(321,757)	(1,141)
Income tax benefit (expense)	(24,782)	18,846	75,391	470
Net income (loss) including non-controlling interests	66,223	(41,064)	(246,366)	(671)
Less: Net income attributable to non-controlling interests	3,882	150	10,907	150
Net income (loss) attributable to Oasis	$62,341	$(41,214)	$(257,273)	$(821)
Earnings (loss) attributable to Oasis per share:				
Basic (Note 15)	$0.20	$(0.18)	$(0.84)	$0.00
Diluted (Note 15)	0.20	(0.18)	(0.84)	0.00
Weighted average shares outstanding:				
Basic (Note 15)	313,167	233,389	305,533	233,248
Diluted (Note 15)	316,387	233,389	305,533	233,248

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

2

Table of Contents

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

	Attributable to Oasis							
	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Non-controlling Interests	Total Stockholders’ Equity
	Shares	Amount	Shares	Amount				
	(In thousands)							
Balance at December 31, 2017	269,295	$ 2,668	1,332	$ (22,179)	$ 2,677,217	$ 717,985	$ 137,888	$ 3,513,579
Permian Basin Acquisition issuance	46,000	460	—	—	370,760	—	—	371,220
Other (2017 issuance of common stock and Oasis Midstream common units)	—	—	—	—	38	—	(125)	(87)
Equity-based compensation	3,881	29	—	—	22,627	—	280	22,936
Distributions to non-controlling interest owners	—	—	—	—	—	—	(10,393)	(10,393)
Treasury stock - tax withholdings	(757)	—	757	(6,806)	—	—	—	(6,806)
Net income (loss)	—	—	—	—	—	(257,273)	10,907	(246,366)
Balance at September 30, 2018	318,419	$ 3,157	2,089	$ (28,985)	$ 3,070,642	$ 460,712	$ 138,557	$ 3,644,083

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

Table of Contents

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

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net loss including non-controlling interests	$(246,366)	$(671)
Adjustments to reconcile net loss including non-controlling interests to net cash provided by operating activities:		
Depreciation, depletion and amortization	465,819	384,246
Loss on extinguishment of debt	13,698	—
Gain on sale of properties	(38,823)	—
Impairment	384,228	6,021
Deferred income taxes	(75,418)	(470)
Derivative instruments	239,945	(52,297)
Equity-based compensation expenses	21,586	20,451
Deferred financing costs amortization and other	20,074	12,666
Working capital and other changes:		
Change in accounts receivable, net	(61,275)	(81,022)
Change in inventory	(12,076)	(235)
Change in prepaid expenses	1,196	823
Change in other current assets	1	276
Change in long-term inventory and other assets	(490)	(12,843)
Change in accounts payable, interest payable and accrued liabilities	50,308	32,282
Change in other current liabilities	—	(10,490)
Change in other liabilities	(406)	—
Net cash provided by operating activities	762,001	298,737
Cash flows from investing activities:		
Capital expenditures	(841,088)	(443,649)
Acquisitions	(579,886)	—
Proceeds from sale of properties	333,029	4,000
Costs related to sale of properties	(2,707)	—
Derivative settlements	(162,013)	(804)
Advances from joint interest partners	(1,038)	(2,502)
Net cash used in investing activities	(1,253,703)	(442,955)
Cash flows from financing activities:		
Proceeds from Revolving Credit Facilities	2,499,000	764,000
Principal payments on Revolving Credit Facilities	(1,959,000)	(732,000)
Repurchase of senior unsecured notes	(423,190)	—
Proceeds from issuance of senior unsecured notes	400,000	—
Deferred financing costs	(7,650)	(96)
Proceeds from sale of Oasis Midstream common units, net of offering costs	—	115,813
Purchases of treasury stock	(6,806)	(6,182)
Distributions to non-controlling interests	(10,393)	—
Other	(87)	(55)
Net cash provided by financing activities	491,874	141,480

Increase (decrease) in cash and cash equivalents	172	(2,738)
Cash and cash equivalents:		
Beginning of period	16,720	11,226
End of period	$16,892	$8,488
Supplemental non-cash transactions:		
Change in accrued capital expenditures	$79,011	$63,499
Change in asset retirement obligations	2,854	3,112
Issuance of shares in connection with the Permian Basin Acquisition	371,220	—
Installment notes from acquisition	—	4,875

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

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 onshore, unconventional oil and natural gas resources in the United States. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct the Company's exploration and production activities and own its proved and unproved oil and natural gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas region of the Delaware Basin, respectively. The Company also operates a midstream services business through OMS Holdings LLC ("OMS") and a well services business through Oasis Well Services LLC ("OWS"), both of which are separate reportable business segments that are complementary to the Company's primary development and production activities. The midstream services business is conducted by Oasis Midstream Partners LP ("OMP" or "Oasis Midstream"), which completed an initial public offering in September 2017. The Company owns the general partner and a majority of the outstanding units of OMP.
2. Summary of Significant Accounting Policies
Basis of Presentation
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, 2017 is derived from audited financial statements. Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income. In the opinion of management, all adjustments, consisting of normal recurring adjustments necessary for the fair statement of the Company's financial position, 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, 2017 ("2017 Annual Report").
Consolidation. The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis, the accounts of wholly-owned subsidiaries, and the accounts of OMP, which is considered a variable interest entity ("VIE") for which the Company is the primary beneficiary. All significant intercompany balances and transactions have been eliminated upon consolidation.
Consolidated VIE. The Company has determined that the partners with equity at risk in OMP lack the authority, through voting rights or similar rights, to direct the activities that most significantly impact OMP's economic performance. Therefore, as the limited partners of OMP do not have substantive kick-out or substantive participating rights over OMP GP LLC ("OMP GP"), the general partner to OMP, OMP is a VIE. Through the Company's ownership interest in OMP GP, the Company has the authority to direct the activities that most significantly affect economic performance and the right to receive benefits that could be potentially significant to OMP. Therefore, the Company is considered the primary beneficiary and consolidates OMP and records a non-controlling interest for the interest owned by the public as of September 30, 2018.
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. A substantial or extended decline in 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.

Table of Contents

Significant Accounting Policies

There have been no material changes to the Company's critical accounting policies and estimates from those disclosed in the 2017 Annual Report, other than as noted below.

Revenue recognition. In the first quarter of 2018, the Company adopted 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 was applied on a modified retrospective basis. The adoption of ASU 2014-09 did not result in a material impact to the Company's financial position, cash flows or results of operations. Enhanced disclosures in accordance with ASU 2014-09 have been provided in Note 3 – Revenue Recognition.

Financial instruments. In the first quarter of 2018, the Company adopted 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 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of September 30, 2018.

Statement of cash flows. In the first quarter of 2018, the Company adopted 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 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of September 30, 2018.

Income taxes. In the first quarter of 2018, the Company adopted Accounting Standards Update No. 2016-16, Intra-Entity Transfers of Assets Other Than Inventory ("ASU 2016-16"), to improve the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. ASU 2016-16 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of September 30, 2018.

In the third quarter of 2018, the Company finalized the accounting related to Accounting Standards Update No. 2018-05, Income Taxes (Topic 740) - Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118 ("ASU 2018-05"). This standard amends Accounting Standards Codification 740, Income Taxes ("ASC 740") to provide guidance on accounting for the tax effects of the Tax Cuts and Jobs Act (the "Tax Act") pursuant to Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act ("SAB 118"). See Note 13 – Income Taxes for the total impact as a result of adoption as of September 30, 2018.

Business combinations. In the first quarter of 2018, the Company adopted Accounting Standards Update No. 2017-01, Clarifying the Definition of a Business ("ASU 2017-01"), which provides guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 requires entities to use a screen test to determine when an integrated set of assets and activities is not a business or if the integrated set of assets and activities needs to be further evaluated against the framework. ASU 2017-01 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of September 30, 2018.

Equity-based compensation. In the first quarter of 2018, the Company adopted Accounting Standards Update No. 2017-09, Scope of Modification Accounting ("ASU 2017-09"), which provides guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. ASU 2017-09 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of September 30, 2018.

Recent Accounting Pronouncements

Leases. In February 2016, the Financial Accounting Standards Board ("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. This standard does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those years.

In January 2018, the FASB issued Accounting Standards Update No. 2018-01, Land Easement Practical Expedient for Transition to Topic 842, which provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under Topic 840, Leases. The Company plans to elect this practical expedient.

In July 2018, the FASB issued Accounting Standards Update No. 2018-11, Targeted Improvements - Lease Topic 842, which allows entities another option for transition and also provides lessors with a practical expedient to combine lease and non-lease components. The Company will adopt the new leases standard using the required modified retrospective approach and plans to elect the option to recognize a cumulative effect adjustment of initially applying the guidance to the opening balance of retained earnings in the period of adoption, rather than recognizing in the earliest period presented. Prior period amounts will not be adjusted.

The Company is in the process of analyzing its lease arrangements and is continuing to identify and put in place necessary changes to its business processes and controls to support the adoption of the new standard, including implementing a new lease accounting software to assess the portfolio of leases, assist in the quantification of the expected impact on the consolidated financial statements and facilitate the calculations of the related accounting entries and disclosures. The Company is currently evaluating the effect that adopting the new lease guidance will have on its financial position, cash flows and results of operations.

Financial instruments. In August 2018, the FASB issued Accounting Standards Update No. 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement (“ASU 2018-13”), which improves the effectiveness of the disclosure requirements for fair value measurements. The changes affect all companies that are required to include fair value measurement disclosures. ASU 2018-13 is effective for fiscal years beginning after December 15, 2019, including interim periods within those years. An entity is permitted to early adopt the removed or modified disclosures upon the issuance of ASU 2018-13 and may delay adoption of the additional disclosures until their effective date. The Company does not expect the adoption of this guidance to have an impact on its financial position, cash flows or results of operations, but it may result in changes to disclosures.

3. Revenue Recognition

In May 2014, the FASB issued a new accounting standard related to revenue recognition, ASC 606 - Revenue from Contracts with Customers (“ASC 606”). This standard was effective in the first quarter of 2018 and the Company adopted the new standard using the modified retrospective method. The Company applied ASC 606 to all new contracts entered into after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of December 31, 2017. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

In accordance with the adoption of ASC 606, management evaluated its contracts with customers to apply the five-step revenue recognition model. The adoption of ASC 606 did not result in a material impact to the Company’s financial position, cash flows or results of operations.

The unit of account in ASC 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. ASC 606 requires that a contract’s transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

Exploration and production revenues

Our exploration and production revenues are derived from contracts for oil, natural gas and natural gas liquids (“NGL”) sales, as described below. Generally, for the majority of these contracts: (i) each unit (barrel (“bbl”), mcf, gallon, etc.) of commodity product is a separate performance obligation, as our promise is to sell multiple distinct units of commodity product at a point in time; (ii) the transaction price principally consists of variable consideration, which amount is determinable each month end based on our right to invoice at month end for the value of commodity product sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity product’s standalone selling price and recognized as revenue upon delivery of the commodity product, which is the point in time when the customer obtains control of the commodity product and our performance obligation is satisfied. The sales of oil, natural gas and NGLs as presented on the Company's Condensed Consolidated Statements of Operations represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling oil, natural gas and NGLs on behalf of royalty owners or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. The Company's contracts with customers typically require payments for oil, natural gas and NGL sales within 30 days following the calendar month of delivery.

Table of Contents

Oil revenues. The Company sells a substantial majority of its oil through bulk sales at delivery points on crude oil gathering systems or directly at the wellhead to a variety of customers under short-term contracts that include a specified quantity of crude oil to be delivered and sold to the customer at a specified delivery point. The customer pays a market-based transaction price, which incorporates differentials that include, but are not limited to, transportation costs and adjustments for product quality.

Natural gas revenues. The Company's natural gas sales consist of unprocessed gas sales and residue gas sales. Unprocessed gas is sold at delivery points at or near the wellhead under various contracts, in which the customer pays a transaction price based on its sale of the bifurcated NGLs and residue gas, less any associated fees. Revenue is recorded on a net basis, with processing fees deducted within revenue rather than as a separate expense line item, as title and control transfer at the delivery point. Residue gas is sold from the tailgate of the Company's gas processing plant located in Wild Basin or transported and sold at other downstream sales points, and the customer pays a transaction price based on a market indexed per-unit rate for the quantities sold.

Purchased oil and gas sales. The Company purchases and sells crude oil and natural gas at various delivery points to a variety of customers under short-term contracts that include specified quantities of crude oil and natural gas to be sold and delivered to the customer at a specified delivery point. The Company purchases and sells crude oil and natural gas to different counterparties at market-based prices. Market-based pricing is based on the price index applicable for the location of the sale. The Company accounts for these transactions on a gross basis.

NGL revenues. NGLs are sold from the Company's gas processing plant complex located in Wild Basin or trucked and sold at other downstream locations, and the customer pays a transaction price based on a market indexed per-unit rate for the quantities sold.

Prior period performance obligations. For sales of oil, purchased oil, natural gas, purchased gas and NGLs, the Company records revenue in the month production is delivered to the purchaser. However, settlement statements and payment may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales once payment is received from the purchaser. Such differences have historically not been significant. The Company uses knowledge of its properties, its properties' historical performance, spot market prices and other factors as the basis for these estimates. For the three and nine months ended September 30, 2018, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Revenues associated with contracts with customers for oil, natural gas and NGL sales were as follows for the three and nine months ended September 30, 2018 and 2017:

Exploration and Production Revenues

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Oil revenues	$412,530	$221,003	$1,097,171	$623,603
Purchased oil sales	42,902	20,734	114,598	56,269
Natural gas revenues	26,181	17,037	76,201	51,689
Purchased gas sales	1,616	462	2,161	648
NGL revenues	13,932	10,607	38,863	29,241
Total exploration and production revenues	$497,161	$269,843	$1,328,994	$761,450

Midstream revenues

Crude oil and natural gas revenues. The Company is party to certain contracts for gas gathering, compression, processing and gas lift services, as well as crude oil gathering, stabilization, blending, storage and transportation. Under these customer contracts, the Company provides daily integrated midstream services on a stand ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the Company’s performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient. Payments from customers are generally received by the Company within one month after the month in which services are provided.

Purchased oil sales. The Company purchases and sells crude oil at various delivery points on crude oil gathering systems to a variety of customers under short-term contracts that include a specified quantity of crude oil to be sold and delivered to the customer at a specified delivery point. The Company purchases and sells the crude oil to different counterparties at market-based prices. Market-based pricing is based on the price index applicable for the location of the sale. The Company accounts for these transactions on a gross basis.

Water revenues. The Company is also party to certain contracts with customers for water services, which includes produced and flowback water gathering and disposal services and freshwater distribution services. Under its customer contracts for produced and flowback water gathering and disposal services, the Company provides daily integrated midstream services on a stand-ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the Company's performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient. Payments from customers are generally received by the Company within one month after the month in which services are provided.

Under its customer contracts for freshwater distribution services, the Company supplies and distributes freshwater to its customers for hydraulic fracturing and production optimization. Management has determined these contracts contain multiple distinct performance obligations since each freshwater barrel is not dependent nor highly interrelated with other barrels. Revenue associated with freshwater distribution services is recognized at a point-in-time based upon the transaction price when title, control and risk of loss transfers to the customer, which occurs at the delivery point. Payments are due from customers 30 days after receipt of invoice.

Revenues associated with contracts with customers for midstream services were as follows for the three and nine months ended September 30, 2018 and 2017:

Midstream Revenues[(1)]

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Crude oil and natural gas revenues	$18,188	$11,612	$54,124	$23,348
Purchased oil sales	1,838	—	5,212	—
Water revenues	12,999	7,155	34,327	25,591
Total midstream revenues	$33,025	$18,767	$93,663	$48,939

(1) Represents midstream revenues, excluding all intercompany revenues, for work performed by the midstream services business segment for the Company's working interests that are eliminated in consolidation and are therefore not included in midstream services revenues.

Well services revenues

Hydraulic fracturing service revenues. Hydraulic fracturing revenue is recognized upon the completion of each hydraulic fracturing of a well. These services are composed of various components, such as personnel, equipment and hydraulic fracturing materials, but management determined that each component is not distinct, as it cannot be used on its own or together with a resource readily available to the customer. Revenue is recognized when the performance obligations of hydraulic fracturing a well in its totality are completed; generally, this is over a period of time due to all work being performed for a customer occurring on the customer's property, where the customer has control over the work in process as it is being performed. In addition, the Company's assets being used to perform the obligations have no alternative use at the time of performance and the Company has the right to payment for performance to date. Payments from customers are generally received by the Company within one month after the month in which services are provided. In addition, revenue from product sales to third parties is generated when OPNA requests that third-party hydraulic fracturing companies hydraulic fracture OPNA's wells. Although the labor is provided by the third-party hydraulic fracturing company, the materials (e.g., sand, chemicals, etc.) used in the hydraulic fracturing of the wells are provided by OWS. The third-party hydraulic fracturing company or OPNA pays OWS for the materials delivered to the wells. Revenue is recognized once the performance obligations to transfer hydraulic fracturing materials are completed.

Equipment rental revenues. Equipment rental revenue is generated when OPNA or a third-party hydraulic fracturing company rents equipment from OWS. This equipment is used in the preparation stage of hydraulic fracturing services or after the hydraulic fracturing services have been completed. Equipment rental revenues are calculated based on the equipment's daily rental rate and the number of days that the equipment was rented by the customer. OWS's performance obligation is satisfied when the entire rental period is completed. Equipment rental revenues are recognized over a period of time due to the customer simultaneously receiving and consuming the benefits of the rental equipment provided by OWS on a daily basis. Satisfaction of the Company's performance obligation is measured at the completion of each day's rental period, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized at the time of invoicing for the entire rental period under the right to invoice practical expedient. Payments from customers are generally received by the Company within one month after the month in which services are provided.

Revenues associated with contracts with customers for hydraulic fracturing services and equipment rental sales were as follows for the three and nine months ended September 30, 2018 and 2017:

Well Services Revenues[(1)]

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Hydraulic fracturing service revenues	$14,985	$15,090	$42,801	$31,303
Equipment rental revenues	1,277	1,048	3,543	2,263
Total well services revenues	$16,262	$16,138	$46,344	$33,566

(1) Represents well services revenues excluding all intercompany revenues for work performed by the well services business segment for the Company's working interests that are eliminated in consolidation and are therefore not included in well services revenues.

Contract balances

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

Performance obligations

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

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

4. Inventory

Crude oil inventory includes oil in tanks. 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. Crude oil inventory and equipment and materials are included in inventory on the Company's Condensed Consolidated Balance Sheets.

The minimum volume of product in a pipeline system that enables the system to operate is known as linefill and is generally not available to be withdrawn from the pipeline system until the expiration of the transportation contract. The Company owns oil linefill in third-party pipelines, which is included in long-term inventory on the Company's Condensed Consolidated Balance Sheets.

Inventory, including long-term inventory, is stated at the lower of cost and net realizable value with cost determined on an average cost method. The Company assesses the carrying value of inventory and uses estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact the Company's estimates are the applicable quality and location differentials to include in the Company's net realizable value analysis. Additionally, the Company estimates the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value.

Table of Contents

Total inventory consists of the following:

	September 30, 2018	December 31, 2017
	(In thousands)	
Inventory		
Crude oil inventory	$14,867	$ 10,427
Equipment and materials	16,542	8,940
Total inventory	$31,409	$ 19,367
Long-term inventory		
Linefill in third-party pipelines	$12,610	$ 12,200
Long-term inventory	$12,610	$ 12,200
Total	$44,019	$ 31,567

5. Accounts Receivable, Net

The following table sets forth the Company's accounts receivable, net:

	September 30, 2018	December 31, 2017
	(In thousands)	
Accounts receivable, net		
Trade accounts	$277,558	$ 233,660
Joint interest accounts	94,793	73,588
Other accounts	56,779	57,905
Total	429,130	365,153
Allowance for doubtful accounts	(946)	(1,573)
Total accounts receivable, net	$428,184	$ 363,580

6. 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's financial instruments, including certain cash and cash equivalents, accounts receivable, accounts payable and other payables, are carried at cost, which approximates their respective fair market values due to their short-term maturities. 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

Table of Contents

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, 2018			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$143	$—	$ —	$143
Total assets	$143	$—	$ —	$143
Liabilities:				
Commodity derivative instruments (see Note 7)	$—	$213,146	$ —	$213,146
Total liabilities	$—	$213,146	$ —	$213,146

	Fair value at December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$142	$—	$ —	$142
Commodity derivative instruments (see Note 7)	—	353	—	353
Total assets	$142	$353	$ —	$495
Liabilities:				
Commodity derivative instruments (see Note 7)	$—	$135,567	$ —	$135,567
Total liabilities	$—	$135,567	$ —	$135,567

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 Sheets at September 30, 2018 and December 31, 2017. The Company's money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identifies the money market funds as Level 1 instruments because the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained, and there are active markets for the underlying investments.
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. 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 \$2.7 million and \$2.8 million at September 30, 2018 and December 31, 2017, respectively.

There were no transfers between fair value levels during the nine months ended September 30, 2018 and December 31, 2017.

Table of Contents

7. 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 contracts will settle monthly based on the average NYMEX West Texas Intermediate crude oil index price (“NYMEX WTI”), the average Intercontinental Exchange, Inc. Brent crude oil index price (“ICE Brent”) and the average Argus WTI Midland crude oil index price (“Midland”). The Company’s natural gas contracts will settle monthly based on the average NYMEX Henry Hub natural gas index price (“NYMEX HH”) and the average Inside FERC Northern Natural Gas Ventura natural gas index price (“IF NNG Ventura”).

At September 30, 2018, the Company utilized fixed price swaps, basis swaps and two-way and three-way costless collars to reduce the price volatility associated with certain of its of oil and natural gas sales. The Company’s fixed price swaps are comprised of a sold call and a purchased put established at the same price (both ceiling and floor), which the Company will receive for the volumes under contract. A basis swap transaction has an established fixed basis differential corresponding to two floating index prices. Depending on the difference of the two floating index prices in relation to the fixed basis differential, the Company either receives an amount from its counterparty, or pays an amount to its counterparty, equal to the difference multiplied by the hedged contract volume. 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 Sheets as either assets or liabilities measured at fair value (see Note 6 – 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 Statements 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 Statements of Cash Flows.

Table of Contents

At September 30, 2018, the Company had the following outstanding commodity derivative instruments:

Commodity	Settlement Period	Derivative Instrument	Index	Volumes		Weighted Average Prices Fixed Price Swaps	Basis Swaps	Sub-Floor	Floor	Ceiling	Fair Valu Asset (Liability
											(In thousa
Crude oil	2018	Fixed price swaps	NYMEX WTI	3,761,000	Bbl	$52.95					$(71,621
Crude oil	2018	Basis swaps	NYMEX WTI-ICE BRENT	152,000	Bbl		$(9.84)				81
Crude oil	2018	Two-way collar	NYMEX WTI	517,000	Bbl				$58.74	$63.94	(5,171
Crude oil	2019	Fixed price swaps	NYMEX WTI	5,613,000	Bbl	$53.33					(99,347
Crude oil	2019	Basis swaps	NYMEX WTI-ICE BRENT	424,000	Bbl		$(9.68)				408
Crude oil	2019	Two-way collar	NYMEX WTI	3,223,000	Bbl				$57.99	$75.46	(7,580
Crude oil	2019	Three-way collar	NYMEX WTI	3,368,000	Bbl			$40.54	$51.03	$68.68	(21,771
Crude oil	2020	Fixed price swaps	NYMEX WTI	403,000	Bbl	$53.47					(5,911
Crude oil	2020	Two-way collar	NYMEX WTI	279,000	Bbl				$57.78	$76.13	(273
Crude oil	2020	Three-way collar	NYMEX WTI	279,000	Bbl			$40.00	$50.56	$67.80	(1,778
Natural gas	2018	Fixed price swaps	NYMEX HH	3,496,000	MMbtu	$3.01					(104
Natural gas	2018	Basis swaps	IF NNG VENTURA-NYMEX HH	1,225,000	MMbtu		$(0.05)				(64
Natural gas	2019	Fixed price swaps	NYMEX HH	1,896,000	MMbtu	$2.95					16
Natural gas	2019	Basis swaps	IF NNG VENTURA-NYMEX HH	2,715,000	MMbtu		$(0.05)				(31
											$(213,14

In October 2018, the Company entered into new swaps and two-way costless collar options for crude oil and natural gas with weighted average floor prices of $64.05 per barrel and $2.88 per MMbtu, respectively. The commodity contracts included total notional amounts of 213,000 barrels, 792,000 barrels and 62,000 barrels which settle in 2018, 2019 and 2020, respectively, based on NYMEX WTI and 305,000 MMbtu and 1,825,000 MMbtu which settle in 2018 and 2019, respectively, based on NYMEX HH. Additionally, the Company entered into new basis swap contracts for crude and natural gas with weighted average differential prices, which represent a reduction of $7.50 per barrel and an addition of $0.13 per MMbtu, respectively. The crude basis swap contracts include total notional amounts of 60,000 barrels and 424,000 barrels, which settle in 2018 and 2019, respectively, based on the differential between Midland and NYMEX WTI, and the natural gas basis swap contracts include total notional amounts of 610,000 MMbtu and 1,810,000 MMbtu, which settle in 2018 and 2019, respectively, based on the differential between IF NNG Ventura and NYMEX HH. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

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 Statements of Operations for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Statements of Operations Location	2018	2017	2018	2017
	(In thousands)			
Net gain (loss) on derivative instruments	$(48,544)	$(54,310)	$(239,945)	$52,297

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 Sheets.

Table of Contents

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

		September 30, 2018		
Commodity	Balance Sheet Location	Gross Recognized Liabilities	Gross Amount Offset	Net Recognized Fair Value Liabilities
		(In thousands)		
Derivatives liabilities:				
Commodity contracts	Derivative instruments — current liabilities	$184,832	$(4,703)	$ 180,129
Commodity contracts	Derivative instruments — non-current liabilities	37,006	(3,989)	33,017
Total derivatives liabilities		$221,838	$(8,692)	$ 213,146

		December 31, 2017		
Commodity	Balance Sheet Location	Gross Recognized Assets/Liabilities	Gross Amount Offset	Net Recognized Fair Value Assets/Liabilities
		(In thousands)		
Derivatives assets:				
Commodity contracts	Derivative instruments — current assets	$344	$—	$ 344
Commodity contracts	Derivative instruments — non-current assets	9	—	9
Total derivatives assets		$353	$—	$ 353
Derivatives liabilities:				
Commodity contracts	Derivative instruments — current liabilities	$117,629	$(1,913)	$ 115,716
Commodity contracts	Derivative instruments — non-current liabilities	20,035	(184)	19,851
Total derivatives liabilities		$137,664	$(2,097)	$ 135,567

8. Property, Plant and Equipment

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

	September 30, 2018	December 31, 2017
	(In thousands)	
Proved oil and gas properties(1)	$7,566,694	$7,058,782
Less: Accumulated depreciation, depletion, amortization and impairment	(2,689,613)	(2,395,153)
Proved oil and gas properties, net	4,877,081	4,663,629
Unproved oil and gas properties	1,104,450	780,173
Other property and equipment	1,088,781	868,746
Less: Accumulated depreciation	(170,175)	(139,062)
Other property and equipment, net	918,606	729,684
Total property, plant and equipment, net	$6,900,137	$6,173,486

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $41.4 million and $39.9 million at September 30, 2018 and December 31, 2017, respectively.

9. Acquisition

Permian Basin Acquisition. On February 14, 2018, the Company acquired from Forge Energy, LLC ("Forge Energy") approximately 22,000 net acres in the Delaware Basin (the "Permian Basin Acquisition") for aggregate consideration consisting of approximately $549.8 million in cash and 46,000,000 shares of the Company's common stock, subject to customary post-closing adjustments (collectively, the "Purchase Price"). In connection with the closing of the Permian Basin Acquisition, the Company and Forge Energy entered into a Registration Rights Agreement that granted the equity holders of Forge Energy certain customary registration rights for the stock portion of the Purchase Price. The

Company funded the cash portion of the Purchase Price with borrowings under a senior secured revolving line of credit among OPNA, as Borrower, Wells Fargo Bank,

Table of Contents

N.A., as administrative agent and the lenders party thereto (the “Oasis Credit Facility”), and proceeds from the Company’s December 2017 issuance of its common stock.

The Permian Basin Acquisition represents the Company’s initial entry into the Delaware Basin. The assets underlying the Permian Basin Acquisition are primarily located in the Bone Spring and Wolfcamp formations of the Delaware sub-basin, across Ward, Winkler, Loving and Reeves Counties, Texas.

The Permian Basin Acquisition qualified as a business combination. As such, the Company estimated the fair value of the assets acquired and liabilities assumed as of the February 14, 2018 acquisition date. The 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). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed under Note 6 — Fair Value Measurements. The Company recorded the assets acquired and liabilities assumed in the Permian Basin Acquisition at their estimated fair value of $921.0 million, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. The Permian Basin Acquisition is considered a taxable transaction; therefore, no deferred tax amounts were recognized at the acquisition date as the tax basis of the assets acquired and liabilities assumed were also recorded at fair value.

The following table summarizes the consideration paid for the Company’s acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date.

	At February 14, 2018 (In thousands)
Consideration paid to Forge Energy:	
Cash	$ 549,770
Common stock: 46,000,000 shares issued	371,220
	$ 920,990
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed properties	$ 110,325
Proved undeveloped properties	166,552
Unproved lease acquisition costs	645,068
Inventory	293
Intangible assets	1,000
Asset retirement obligations	(2,248)
	$ 920,990

The results of operations for the Permian Basin Acquisition have been included in the Company’s condensed consolidated financial statements since the February 14, 2018 closing date, including $19.4 million and $51.0 million of total revenue and $3.9 million and $14.2 million of operating income for the three and nine months ended September 30, 2018, respectively.

The Company also recorded a $1.0 million finite-lived intangible asset on the Company’s Condensed Consolidated Balance Sheets for a non-compete agreement with a one-year life. Intangible assets are amortized on a straight-line basis over the useful life, and the Company includes the amortization in depreciation, depletion and amortization expenses on the Company’s Condensed Consolidated Statements of Operations. For the three and nine months ended September 30, 2018, amortization expense recognized for this non-compete agreement was approximately $0.3 million and $0.6 million, respectively.

Summarized below are the consolidated results of operations for the three and nine months ended September 30, 2018, on an unaudited pro forma basis, as if the acquisition and related financing had occurred on January 1, 2017. The unaudited pro forma financial information was derived from the historical consolidated statements of operations of the Company and the statement of revenues and direct operating expenses for the Permian Basin Acquisition properties, which were derived from the historical accounting records of Forge Energy. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the acquisition and related financing occurred on the basis assumed above, nor is such information indicative of the Company's expected future results of operations.

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)		(In thousands)	
	Unaudited		Unaudited	
Revenues	$546,449	$318,879	$1,474,530	$871,952
Net income (loss) attributable to Oasis	62,341	(29,717)	(252,731)	22,068
Net income (loss) attributable to Oasis per share:				
Basic	$0.20	$(0.11)	$(0.81)	$0.08
Diluted	0.20	(0.11)	(0.81)	0.08

Other Delaware Acquisition. On September 12, 2018, the Company completed the initial closing with undisclosed sellers to acquire certain exploration and production assets adjacent to the Company's existing Delaware position (the "Other Delaware Acquisition") for total cash consideration of $59.5 million. Based on the FASB's authoritative guidance, the acquisition qualified as a business combination, and as such, the Company estimated the fair value of the assets acquired as of the acquisition date. The Company recorded the oil and gas properties acquired at their estimated fair value of $59.5 million, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized.

The results of operations for the acquisition have been included in the Company's consolidated financial statements since the closing date. Pro forma information is not presented as the pro forma results would not be materially different from the information presented in the Company's Consolidated Statement of Operations.

10. Divestitures

Williston Non-Op Divestiture. On July 10, 2018, the Company completed the initial closing for the sale of certain non-operated oil and gas properties in the Williston Basin (the "Williston Non-Op Divestiture"). The transaction had an effective date of March 1, 2018, and the final closing statement will be completed in the fourth quarter of 2018. Upon the initial closing, the Company recognized a $27.5 million net gain on sale of properties, which is subject to customary closing adjustments, in its Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2018. The divested properties were in the Company's exploration and production segment.

Foreman Butte Divestiture. On July 31, 2018, the Company completed the initial closing for the sale of oil and gas properties and certain other property and equipment primarily located in the Foreman Butte area of the Williston Basin (the "Foreman Butte Divestiture"). The transaction had an effective date of March 1, 2018, and the final closing statement will be completed in the first quarter of 2019. During the second quarter of 2018, the Company recorded an impairment loss of $383.4 million, which was included in impairment on the Company's Condensed Consolidated Statements of Operations, to adjust the carrying value of these assets to their estimated fair value, determined based on the expected sales price as negotiated with the purchaser, less costs to sell. Upon the initial closing, the Company recognized a $10.1 million net loss on sale of properties, which is subject to customary closing adjustments, in its Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2018. The Foreman Butte Divestiture 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.

Other Williston Divestiture. On August 17, 2018, the Company completed the initial closing for the sale of additional non-strategic oil and gas properties in the Williston Basin (the "Other Williston Divestiture"). The transaction had an effective date of March 1, 2018, and the final closing statement will be completed in the first quarter of 2019. Upon the initial closing, the Company recognized a $19.4 million net gain on sale of properties, which is subject to customary closing adjustments, in its Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2018. The divested properties were in the Company's exploration and production segment.

Table of Contents

11. Long-Term Debt
The Company's long-term debt consists of the following:

	September 30, 2018	December 31, 2017
	(In thousands)	
Oasis Credit Facility	$522,000	$70,000
OMP Credit Facility	166,000	78,000
Senior unsecured notes		
7.25% senior unsecured notes due February 1, 2019	—	54,275
6.50% senior unsecured notes due November 1, 2021	71,835	395,501
6.875% senior unsecured notes due March 15, 2022	901,480	937,080
6.875% senior unsecured notes due January 15, 2023	366,094	366,094
6.25% senior unsecured notes due May 1, 2026	400,000	—
2.625% senior unsecured convertible notes due September 15, 2023	300,000	300,000
Total principal of senior unsecured notes	2,039,409	2,052,950
Less: unamortized deferred financing costs on senior unsecured notes	(22,212)	(22,956)
Less: unamortized debt discount on senior unsecured convertible notes	(72,188)	(80,388)
Total long-term debt	$2,633,009	$2,097,606

The carrying amount of the Company's long-term debt reported in the Condensed Consolidated Balance Sheet at September 30, 2018 was $2,633.0 million, which included $2,039.4 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 $72.2 million and $22.2 million, respectively, $522.0 million of borrowings under the Oasis Credit Facility and $166.0 million of borrowings under a $250.0 million senior secured revolving credit facility among OMP, as parent, OMP Operating LLC, a subsidiary of OMP, as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "OMP Credit Facility," and, together with the Oasis Credit Facility, the "Revolving Credit Facilities"). The Revolving Credit Facilities are recorded at values that approximate fair value since their variable interest rates are tied to current market rates. The fair value of the Company's senior unsecured notes, which are publicly traded and therefore categorized as Level 1 liabilities, was $2,172.3 million at September 30, 2018.

Senior secured revolving line of credit. The Company has the Oasis Credit Facility with an overall senior secured line of credit of $2,500.0 million as of September 30, 2018, which has a maturity date of April 13, 2020. The Oasis 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 26, 2018, the Company entered into an amendment to the Oasis Credit Facility, resulting in the aggregate elected commitment being increased from $1,150.0 million to $1,350.0 million and two new lenders being added to the bank group. On April 19, 2018, the lenders under the Oasis Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2018, resulting in the Company entering into the Twelfth Amendment to the Second Amended and Restated Credit Agreement to the Oasis Credit Facility, which (i) reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, (ii) removed the legacy anti-cash hoarding provisions, (iii) reduced the coverage threshold with respect to mortgaged properties and (iv) amended the asset sale covenant to give the Company additional flexibility to trade oil and gas properties. In addition, in connection with such amendment, OP Permian became a guarantor under the Oasis Credit Facility.

On October 16, 2018, the Company entered into a third amended and restated credit agreement (the "Third Amended Credit Facility"). In connection with entry into the Third Amended Credit Facility, the semi-annual redetermination of the Company's borrowing base was completed on October 16, 2018, which reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, and the overall credit facility increased from $2,500.0 million to $3,000.0 million. Pursuant to the Third Amended Credit Facility, the credit facility was extended from April 2020 to October 2023, provided that the Company's 2022 and 2023 Senior Notes are retired or refinanced 90 days prior to their respective maturities. All other significant rates, terms and conditions of the Third Amended Credit Facility remained the same. The next redetermination of the Oasis Credit Facility's borrowing base is scheduled for April 1, 2019.

At September 30, 2018, the Company had $522.0 million of London Interbank Offered Rate ("LIBOR") loans at a weighted average interest rate of 3.9% and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing base committed capacity of $814.0 million. On a quarterly basis, the Company also pays a commitment fee that can range from 0.375% to 0.500% 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 Oasis Credit Facility as of September 30, 2018.

OMP Operating LLC revolving line of credit. Through its ownership of OMP, the Company has access to the OMP Credit Facility with a revolving line of credit of $250.0 million, which has a maturity date of September 25, 2022. On August 27, 2018, OMP entered into an amendment to its revolving credit facility to the OMP Credit Facility in order to (i) increase the aggregate amount of commitments from $200.0 million to $250.0 million, (ii) provide for the ability to further increase commitments and (iii) add six new lenders to the bank group. The OMP Credit Facility is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. The OMP Credit Facility includes a letter of credit sublimit of $10.0 million and a swingline loans sublimit of $10.0 million. The borrowing capacity on the OMP Credit Facility may be increased up to $400.0 million, subject to certain conditions.

Borrowings under the OMP Credit Facility bear interest at a rate per annum equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the OMP Credit Facility) or (ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the OMP Credit Facility). The applicable margin for borrowings under the OMP Credit Facility varies from (a) in the case of Eurodollar Loans, 1.75% to 2.75% and (b) in the case of ABR Loans or swingline loans, 0.75% to 1.75%. The unused portion of the OMP Credit Facility is subject to a commitment fee ranging from 0.375% to 0.500%.

The OMP Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (i) consolidated leverage ratio, (ii) consolidated secured leverage ratio and (iii) consolidated interest coverage ratio (each covenant as described in the OMP Credit Facility). OMP Operating LLC was in compliance with the financial covenants of the OMP Credit Facility as of September 30, 2018. All obligations of OMP Operating LLC, as the borrower under the OMP Credit Facility, are unconditionally guaranteed on a joint and several basis by OMP, OMP Operating LLC and Bighorn DevCo LLC.

At September 30, 2018, the Company had $166.0 million of borrowings outstanding under the OMP Credit Facility. As of September 30, 2018, the weighted average interest rate on borrowings under the OMP Credit Facility was 4.0%.

Senior unsecured notes. On May 14, 2018, the Company completed its offering of $400.0 million in aggregate principal amount of its 6.25% senior unsecured notes due 2026 (the “2026 Notes”). The Company used the net proceeds of $394.4 million from the 2026 Notes to fund the repurchase of certain outstanding senior notes (the “Tender Offers”), as described below. At September 30, 2018, the Company had $1,739.4 million principal amount of senior unsecured notes outstanding with maturities ranging from November 2021 to May 2026 and coupons ranging from 6.25% to 6.875% (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.

On May 25, 2018, the Company completed the Tender Offers and, as a result of the Tender Offers, the Company repurchased an aggregate principal amount of $390.6 million of its outstanding Senior Notes, consisting of $31.3 million principal amount of its 7.25% senior unsecured notes due 2019 (the “2019 Notes”), $323.7 million principal amount of its 6.50% senior unsecured notes due 2021 and $35.6 million principal amount of its 6.875% senior unsecured notes due 2022, for an aggregate cost of $402.0 million, including accrued interest and fees.

On May 29, 2018, the Company paid $23.0 million to redeem all of the remaining outstanding 2019 Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the 2019 Notes. The Company financed the redemption with borrowings under the Oasis Credit Facility. As a result of the Tender Offers and the redemption, the Company recognized a pre-tax loss of $13.7 million, which was net of unamortized deferred financing costs write-offs of $4.0 million, and is reflected in loss on extinguishment of debt in the Company’s Condensed Consolidated Statements of Operations for the nine months ended September 30, 2018. As of September 30, 2018, no 2019 Notes remained outstanding.

Senior unsecured convertible notes. At September 30, 2018, the Company had 300.0 million of 2.625% senior unsecured convertible notes due September 2023 (the “Senior Convertible Notes”). 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 (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, 2018, 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.

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.

12. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the nine months ended September 30, 2018:

	(In thousands)
Balance at December 31, 2017	$ 48,799
Liabilities incurred during period	5,509
Liabilities settled during period	(4,904)
Accretion expense during period[1]	1,975
Revisions to estimates	83
Balance at September 30, 2018	$ 51,462

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

At September 30, 2018, the current portion of the total ARO balance was approximately $0.1 million and was included in accrued liabilities on the Company's Condensed Consolidated Balance Sheets.

13. Income Taxes

The Company's effective tax rate for the three and nine months ended September 30, 2018 was 27.2% and 23.4%, respectively, as compared to an effective tax rate of 31.5% and 41.2% for the three and nine months ended September 30, 2017, respectively. The effective tax rate for the three months ended September 30, 2018 was higher than the statutory federal rate of 21% primarily due to state income taxes and the impact of non-deductible executive compensation. The effective tax rate for the nine months ended September 30, 2018 was higher than the statutory rate primarily due to state income taxes and the impact of a change in the blended state rate at which the Company's deferred taxes are recorded, partially offset by the impact of non-deductible executive compensation.

The effective tax rate for the three months ended September 30, 2017 was lower than the statutory federal rate of 35% primarily due to the impact of non-deductible executive compensation and equity-based compensation shortfalls, partially offset by state income taxes. The effective tax rate for the nine months ended September 30, 2017 was higher than the statutory federal rate of 35% primarily due to state income taxes, the impact of non-deductible executive compensation and equity-based compensation windfalls, partially offset by the portion of OMP's earnings attributable to the non-controlling public limited partners, which are not taxable to the Company.

Valuation allowance. The Company had valuation allowances of $3.3 million and $1.2 million as of September 30, 2018 and December 31, 2017, respectively, because the Company has concluded it is more likely than not that it will be unable to utilize certain state net operating loss carryforwards and charitable contribution carryforwards. As of each reporting date, the Company's management considers new evidence, both positive and negative, which could impact management's view with regard to future realization of deferred tax assets. During the nine months ended September 30, 2018, the valuation allowance was increased by $2.1 million, primarily against the Company's Montana net operating loss carryforwards, as a result of the Permian Basin Acquisition and the corresponding shift of projected future taxable income into other states. During the three months ended September 30, 2018, there was no material change to the valuation allowance.

Tax Cuts and Jobs Act. On December 22, 2017, the U.S. government enacted the Tax Act, which made broad and complex changes to the U.S. tax code. Due to the complexities involved in the accounting for the enactment of the new law, the SEC issued SAB 118, which provides guidance on the accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740, "Income Taxes." In accordance with SAB 118, the Company was able to make reasonable estimates on certain effects of the Tax Act in the financial statements as of December 31, 2017. During the three months ended September 30, 2018, the Company completed the accounting under the Tax Act. Based on additional guidance issued by the Internal Revenue Service regarding the grandfather provisions related to certain performance-based compensation awards outstanding as of November 2, 2017, the Company wrote off $1.9 million of deferred tax assets for which the Company will not receive a future tax deduction.

14. Equity-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 awards 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.

During the nine months ended September 30, 2018, employees and non-employee directors of the Company were granted restricted stock awards equal to 3,511,030 shares of common stock with a $10.17 weighted average grant date per share value. Equity-based compensation expense recorded for restricted stock awards for the three and nine months ended September 30, 2018 was $5.1 million and $14.7 million, respectively, and $4.9 million and $15.2 million for the three and nine months ended September 30, 2017, respectively. Equity-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statements 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.

The Company accounts for 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. 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. 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 for the Monte Carlo model are the forecast period, initial value, stock price on the date of grant, risk-free interest rate, volatility and correlation coefficients. The risk-free interest rates are the U.S. Treasury bond rates on the date of grant that correspond to each 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 was calculated from the daily historical returns of stock prices 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 equity-based compensation expense of the PSUs granted during the nine months ended September 30, 2018:

Table of Contents

Risk-free interest rate	2.08% - 2.31%
Oasis volatility	72.88 %
Oasis initial value	$8.82
Oasis stock price on date of grant	$9.27

During the nine months ended September 30, 2018, officers of the Company were granted 854,400 PSUs with a $12.71 weighted average grant date per unit value. Equity-based compensation expense recorded for PSUs for the three and nine months ended September 30, 2018 was $2.2 million and $6.3 million, respectively, and $1.6 million and $5.1 million for the three and nine months ended September 30, 2017, respectively. Equity-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statements of Operations.

OMP phantom unit awards. The Company has granted OMP phantom unit awards (collectively, the "OMP Phantom Unit Awards," and each an "OMP Phantom Unit") to employees under its Amended and Restated 2010 Long Term Incentive Plan in 2018, and in 2017, under OMP GP's Oasis Midstream Partners LP 2017 Long Term Incentive Plan ("OMP LTIP").

Each OMP Phantom Unit represents the right to receive, upon vesting of the award, a cash payment equal to the fair market value of one OMP common unit on the day prior to the date it vests (the "Vesting Date"). Award recipients are also entitled to Distribution Equivalent Rights ("DER") with respect to each OMP Phantom Unit received. Each DER represents the right to receive, upon vesting of the award, a cash payment equal to the value of the distributions paid on one OMP common unit between the Grant Date and the applicable Vesting Date. The OMP Phantom Unit Awards vest in equal amounts each year over a three-year period, and compensation expense will be recognized over the requisite service period and is included in general and administrative expenses on the Company's Condensed Consolidated Statements of Operations.

The OMP Phantom Unit Awards are accounted for as liability-classified awards since the awards will settle in cash, and equity-based compensation cost is accounted for under the fair value method in accordance with GAAP. Under the fair value method for liability-classified awards, compensation cost is remeasured each reporting period at fair value based upon the closing price of a publicly traded common unit. The Company will directly pay, or will reimburse OMP, for the cash settlement amount of these awards.

During the nine months ended September 30, 2018, the Company granted 87,480 OMP Phantom Unit Awards to certain employees of Oasis. Equity-based compensation expense recorded for the OMP Phantom Unit Awards for the three and nine months ended September 30, 2018 was $0.2 million and $0.4 million, respectively. The Company did not record any equity-based compensation related to the OMP Phantom Unit Awards for the three and nine months ended September 30, 2017 because these awards were first granted in the fourth quarter of 2017.

OMP restricted unit awards. During the nine months ended September 30, 2018, independent directors of OMP were granted 17,260 restricted unit awards which vest over a one-year period with a weighted average grant date fair value of $17.55 per common unit. These awards are accounted for as equity-classified awards since the awards will settle in common units upon vesting. Equity-based compensation cost is accounted for under the fair value method in accordance with GAAP. Under the fair value method for equity-classified awards, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. Compensation cost associated with these awards was approximately $0.1 million and $0.3 million for the three and nine months ended September 30, 2018, respectively, and is included in general and administrative expenses on the Company's Condensed Consolidated Statements of Operations.

15. Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing the earnings (loss) attributable to Oasis common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings (loss) per share includes the potential dilutive impact of unvested restricted stock awards and contingently issuable shares related to PSUs and the Senior Convertible Notes during the periods presented, unless their effect is anti-dilutive. There are no adjustments made to the income (loss) attributable to Oasis available to common stockholders in the calculation of diluted earnings (loss) per share.

Table of Contents

The following is a calculation of the basic and diluted weighted average shares outstanding for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Basic weighted average common shares outstanding	313,167	233,389	305,533	233,248
Dilutive effect of restricted stock awards and PSUs[1]	3,220	—	—	—
Diluted weighted average common shares outstanding	316,387	233,389	305,533	233,248

(1) No unvested stock awards were included in computing earnings (loss) per share for the nine months ended September 30, 2018 and the three and nine months ended September 30, 2017 because the effects were anti-dilutive.

For the nine months ended September 30, 2018 and the three and nine months ended September 30, 2017, the Company incurred a net loss, and therefore the diluted loss per share calculation for the period excludes the anti-dilutive effect of unvested stock awards. In addition, the Company excluded these unvested stock awards from the diluted earnings (loss) per share calculation for the three months ended September 30, 2018 because the effects were anti-dilutive based on the treasury stock method. The following is a calculation of weighted average common shares excluded from diluted earnings (loss) per share due to the anti-dilutive effect:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Restricted stock awards and PSUs	4,180	5,841	7,284	5,988

The Company issued its Senior Convertible Notes in September 2016 (see Note 11 – Long-Term Debt). 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. 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, 2018, 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, 2018.

16. 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 midstream services business segment ("OMS") performs produced and flowback water gathering and disposal services, fresh water services, natural gas gathering and processing and crude oil gathering and transportation and other midstream services for the Company's oil and natural gas wells operated by OPNA and other third-party operators. Revenues for the midstream segment are primarily derived from produced and flowback water pipeline transport, produced and flowback water disposal, fresh water sales, natural gas gathering and processing and crude oil gathering, blending, stabilization and transportation. The Company's well services business segment ("OWS") performs completion 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 revenues and expenses related to work performed by OMS and OWS 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 Statements 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.

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 ("DD&A"). The following table summarizes financial information for the Company's three business segments for the periods presented:

Table of Contents

	Exploration and Production	Midstream Services	Well Services	Eliminations	Consolidated
	(In thousands)				
Three months ended September 30, 2018:					
Revenues from non-affiliates	$497,161	$33,025	$16,262	$—	$546,448
Inter-segment revenues	—	42,745	40,177	(82,922)	—
Total revenues	497,161	75,770	56,439	(82,922)	546,448
Operating income	146,969	31,326	9,237	(8,487)	179,045
Other expense	(87,594)	(367)	(79)	—	(88,040)
Income before income taxes including non-controlling interests	$59,375	$30,959	$9,158	$(8,487)	$91,005
Three months ended September 30, 2017:					
Revenues from non-affiliates	$269,843	$18,767	$16,138	$—	$304,748
Inter-segment revenues	—	28,893	31,025	(59,918)	—
Total revenues	269,843	47,660	47,163	(59,918)	304,748
Operating income	3,484	25,194	10,802	(7,086)	32,394
Other income (expense)	(92,319)	(15)	30	—	(92,304)
Income (loss) before income taxes including non-controlling interests	$(88,835)	$25,179	$10,832	$(7,086)	$(59,910)
Nine months ended September 30, 2018:					
Revenues from non-affiliates	$1,328,994	$93,663	$46,344	$—	$1,469,001
Inter-segment revenues	—	119,095	114,898	(233,993)	—
Total revenues	1,328,994	212,758	161,242	(233,993)	1,469,001
Operating income (loss)	(53,159)	101,457	25,415	(24,357)	49,356
Other expense	(370,311)	(703)	(99)	—	(371,113)
Income (loss) before income taxes including non-controlling interests	$(423,470)	$100,754	$25,316	$(24,357)	$(321,757)
Nine months ended September 30, 2017:					
Revenues from non-affiliates	$761,450	$48,939	$33,566	$—	$843,955
Inter-segment revenues	—	76,674	68,028	(144,702)	—
Total revenues	761,450	125,613	101,594	(144,702)	843,955
Operating income (loss)	(12,972)	69,059	9,161	(7,383)	57,865
Other income (expense)	(59,027)	(13)	34	—	(59,006)
Income (loss) before income taxes including non-controlling interests	$(71,999)	$69,046	$9,195	$(7,383)	$(1,141)
At September 30, 2018:					
Property, plant and equipment, net	$6,227,767	$841,797	$41,468	$(210,895)	$6,900,137
Total assets[(1)]	6,675,626	867,226	49,285	(175,706)	7,416,431
At December 31, 2017:					
Property, plant and equipment, net	$5,663,323	$649,923	$46,779	$(186,539)	$6,173,486
Total assets[(1)]	6,050,255	663,614	52,800	(151,539)	6,615,130

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

Table of Contents

17. Commitments and Contingencies

Included below is a discussion of the Company's various future commitments as of September 30, 2018 and subsequent to September 30, 2018. The commitments under these arrangements are not recorded in the accompanying Condensed Consolidated Balance Sheets. The amounts disclosed represent undiscounted cash flows on a gross basis, and no inflation elements have been applied.

Volume commitment agreements. As of September 30, 2018 and subsequent to September 30, 2018, the Company had certain agreements with an aggregate requirement to deliver or transport a minimum quantity of approximately 50.9 MMBbl of crude oil, 43.5 MMBbl of natural gas liquids, 901.3 Bcf of natural gas and 30.8 MMBbl of water, prior to any applicable volume credits, within specified timeframes, all of which are ten years or less. The estimable future commitments under these agreements were approximately \$550.5 million as of September 30, 2018 and \$650.2 million subsequent to September 30, 2018. The future commitments under certain agreements cannot be estimated as they are based on fixed differentials relative to NYMEX WTI under the agreements as compared to the differential relative to NYMEX WTI for the Williston Basin for the production month.

Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. 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.

Mirada litigation. On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, "Mirada") filed a lawsuit against Oasis, OPNA and Oasis Midstream Services LLC, seeking monetary damages in excess of \$100 million, declaratory relief, attorneys' fees and costs (Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). Mirada asserts that it is a working interest owner in certain acreage owned and operated by the Company in Wild Basin. Specifically, Mirada asserts that the Company has breached certain agreements by: (1) failing to allow Mirada to participate in the Company's midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada's consent prior to drilling more than one well at a time in Wild Basin; and (4) overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that the Company be removed as operator in Wild Basin at Mirada's election and that Mirada be allowed to elect a new operator; certain agreements apply to the Company and Mirada and Wild Basin with respect to this dispute; the Company be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and the Company not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada's consent. Mirada also seeks a declaratory judgment with respect to the Company's current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in the Company's Wild Basin midstream operations, consisting of produced water disposal, crude oil gathering and gas gathering and processing; that, upon Mirada's election to participate, Mirada is obligated to pay its proportionate costs of the Company's midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the "Contract Area." On June 30, 2017, Mirada amended its original petition to add a claim that the Company has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleged new legal theories for being entitled to enforce the underlying contracts and added Bighorn DevCo LLC, Bobcat DevCo LLC and Beartooth DevCo LLC as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On March 2, 2018, Mirada filed a fourth amended petition that described Mirada's alleged ownership and assignment of interests in assets purportedly governed by agreements at issue in the lawsuit. On August 31, 2018, Mirada filed a fifth amended petition that added Oasis Midstream Partners, LP as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

The Company believes that Mirada's claims are without merit, that the Company has complied with its obligations under the applicable agreements and that some of Mirada's claims are grounded in agreements that do not apply to the Company. The Company filed answers denying all of Mirada's claims and intends and continues to vigorously defend against Mirada's claims. OMP has not yet filed an answer because it has not yet been served with process. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the

Table of Contents

claim. Trial is currently scheduled for May 2019. However, the Company cannot predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Company's interests, or if the Company were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Company's business, financial condition, results of operations or cash flows. Such an adverse determination could materially impact the Company's ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in the Company's midstream operations could materially reduce the interests of the Company in their current assets and future midstream opportunities and related revenues in Wild Basin. In addition, the Company has agreed to indemnify OMP for any losses resulting from this litigation under the omnibus agreement it entered into with OMP at the time of OMP's initial public offering.

18. Condensed Consolidating Financial Information

The Notes (see Note 11 – 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 operating units, including OMP, which is accounted for on a consolidated basis, do not guarantee the Notes ("Non-Guarantor Subsidiaries").

The following financial information reflects consolidating financial information of the parent company, Oasis Petroleum Inc. ("Issuer"), its Guarantors on a combined basis and the Non-Guarantor Subsidiaries on a combined basis, prepared on the equity basis of accounting. 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, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands, except share data)				
ASSETS					
Current assets					
Cash and cash equivalents	$170	$11,732	$ 4,990	$—	$16,892
Accounts receivable, net	—	423,130	5,054	—	428,184
Accounts receivable - affiliates	653,255	66,153	72,896	(792,304)	—
Inventory	—	31,409	—	—	31,409
Prepaid expenses	617	5,731	96	—	6,444
Intangible assets, net	—	375	—	—	375
Other current assets	—	192	—	—	192
Total current assets	654,042	538,722	83,036	(792,304)	483,496
Property, plant and equipment					
Oil and gas properties (successful efforts method)	—	8,679,662	—	(8,518)	8,671,144
Other property and equipment	—	212,257	876,534	(10)	1,088,781
Less: accumulated depreciation, depletion, amortization and impairment	—	(2,805,233)	(54,555)	—	(2,859,788)
Total property, plant and equipment, net	—	6,086,686	821,979	(8,528)	6,900,137
Investments in and advances to subsidiaries	4,653,951	515,997	—	(5,169,948)	—
Deferred income taxes	209,919	—	—	(209,919)	—
Long-term inventory	—	12,610	—	—	12,610
Other assets	—	18,207	1,981	—	20,188
Total assets	$5,517,912	$7,172,222	$ 906,996	$(6,180,699)	$7,416,431
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities					
Accounts payable	$—	$17,182	$ 24	$—	$17,206
Accounts payable - affiliates	41,213	726,151	24,940	(792,304)	—
Revenues and production taxes payable	—	286,897	436	—	287,333
Accrued liabilities	56	248,097	59,373	—	307,526
Accrued interest payable	19,855	547	172	—	20,574
Derivative instruments	—	180,129	—	—	180,129
Advances from joint interest partners	—	3,878	—	—	3,878
Other current liabilities	—	40	—	—	40
Total current liabilities	61,124	1,462,921	84,945	(792,304)	816,686
Long-term debt	1,945,009	522,000	166,000	—	2,633,009
Deferred income taxes	—	440,423	—	(209,919)	230,504
Asset retirement obligations	—	49,860	1,497	—	51,357
Derivative instruments	—	33,017	—	—	33,017
Other liabilities	—	7,775	—	—	7,775
Total liabilities	2,006,133	2,515,996	252,442	(1,002,223)	3,772,348
Stockholders' equity					
Capital contributions from affiliates	—	3,271,788	202,007	(3,473,795)	—

Common stock, $0.01 par value: 900,000,000 shares authorized; 320,507,783 shares issued and 318,419,144 shares outstanding	3,157	—	—	—	3,157
Treasury stock, at cost: 2,088,639 shares	(28,985)	—	—	—	(28,985)
Additional paid-in-capital	3,070,642	9,141	—	(9,141)	3,070,642
Retained earnings	466,965	1,236,740	46,413	(1,289,406)	460,712
Oasis share of stockholders' equity	3,511,779	4,517,669	248,420	(4,772,342)	3,505,526
Non-controlling interests	—	138,557	406,134	(406,134)	138,557
Total stockholders' equity	3,511,779	4,656,226	654,554	(5,178,476)	3,644,083
Total liabilities and stockholders' equity	$5,517,912	$7,172,222	$ 906,996	$(6,180,699)	$7,416,431

27

Table of Contents

Condensed Consolidating Balance Sheet

	December 31, 2017				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands, except share data)				
ASSETS					
Current assets					
Cash and cash equivalents	$178	$15,659	$ 883	$—	$16,720
Accounts receivable, net	—	362,746	834	—	363,580
Accounts receivable - affiliates	425,668	46,020	85,818	(557,506)	—
Inventory	—	19,367	—	—	19,367
Prepaid expenses	267	6,586	778	—	7,631
Derivative instruments	—	344	—	—	344
Other current assets	—	193	—	—	193
Total current assets	426,113	450,915	88,313	(557,506)	407,835
Property, plant and equipment					
Oil and gas properties (successful efforts method)	—	7,840,921	—	(1,966)	7,838,955
Other property and equipment	—	214,818	653,928	—	868,746
Less: accumulated depreciation, depletion, amortization and impairment	—	(2,499,867)	(34,348)	—	(2,534,215)
Total property, plant and equipment, net	—	5,555,872	619,580	(1,966)	6,173,486
Investments in and advances to subsidiaries	4,790,976	422,132	—	(5,213,108)	—
Derivative instruments	—	9	—	—	9
Deferred income taxes	183,568	—	—	(183,568)	—
Long-term inventory	—	12,200	—	—	12,200
Other assets	—	19,587	2,013	—	21,600
Total assets	$5,400,657	$6,460,715	$ 709,906	$(5,956,148)	$6,615,130
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities					
Accounts payable	$—	$13,370	$ —	$—	$13,370
Accounts payable - affiliates	34,382	511,486	11,638	(557,506)	—
Revenues and production taxes payable	—	213,995	—	—	213,995
Accrued liabilities	216	177,446	58,818	—	236,480
Accrued interest payable	38,796	53	114	—	38,963
Derivative instruments	—	115,716	—	—	115,716
Advances from joint interest partners	—	4,916	—	—	4,916
Other current liabilities	—	40	—	—	40
Total current liabilities	73,394	1,037,022	70,570	(557,506)	623,480
Long-term debt	1,949,606	70,000	78,000	—	2,097,606
Deferred income taxes	—	489,489	—	(183,568)	305,921
Asset retirement obligations	—	47,195	1,316	—	48,511
Derivative instruments	—	19,851	—	—	19,851
Other liabilities	—	6,182	—	—	6,182
Total liabilities	2,023,000	1,669,739	149,886	(741,074)	3,101,551
Stockholders' equity					

Capital contributions from affiliates	—	3,264,691	234,935	(3,499,626)	—
Common stock, $0.01 par value: 450,000,000 shares authorized; 270,627,014 shares issued and 269,295,466 shares outstanding	2,668	—	—	—	2,668
Treasury stock, at cost: 1,331,548 shares	(22,179)	—	—	—	(22,179)
Additional paid-in-capital	2,677,217	8,922	—	(8,922)	2,677,217
Retained earnings	719,951	1,379,475	11,639	(1,393,080)	717,985
Oasis share of stockholders' equity	3,377,657	4,653,088	246,574	(4,901,628)	3,375,691
Non-controlling interests	—	137,888	313,446	(313,446)	137,888
Total stockholders' equity	3,377,657	4,790,976	560,020	(5,215,074)	3,513,579
Total liabilities and stockholders' equity	$5,400,657	$6,460,715	$ 709,906	$(5,956,148)	$6,615,130

Table of Contents

Condensed Consolidating Statement of Operations

	Three Months Ended September 30, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Revenues					
Oil and gas revenues	$—	$ 452,643	$ —	$ —	$ 452,643
Purchased oil and gas sales	—	46,356	—	—	46,356
Midstream revenues	—	765	71,467	(41,045)	31,187
Well services revenues	—	16,262	—	—	16,262
Total revenues	—	516,026	71,467	(41,045)	546,448
Operating expenses					
Lease operating expenses	—	63,099	—	(14,565)	48,534
Midstream operating expenses	—	528	19,816	(11,692)	8,652
Well services operating expenses	—	11,405	—	—	11,405
Marketing, transportation and gathering expenses	—	36,839	—	(6,126)	30,713
Purchased oil and gas expenses	—	46,148	—	(60)	46,088
Production taxes	—	38,722	—	—	38,722
Depreciation, depletion and amortization	—	159,843	7,189	(4,048)	162,984
Exploration expenses	—	22,315	—	—	22,315
General and administrative expenses	7,486	24,627	5,449	(2,703)	34,859
Total operating expenses	7,486	403,526	32,454	(39,194)	404,272
Gain on sale of properties	—	36,869	—	—	36,869
Operating income (loss)	(7,486)	149,369	39,013	(1,851)	179,045
Other income (expense)					
Equity in earnings of subsidiaries	96,555	38,835	—	(135,390)	—
Net loss on derivative instruments	—	(48,544)	—	—	(48,544)
Interest expense, net of capitalized interest	(32,836)	(6,561)	(163)	—	(39,560)
Loss on extinguishment of debt	(47)	—	—	—	(47)
Other income (expense)	—	126	(15)	—	111
Total other income (expense)	63,672	(16,144)	(178)	(135,390)	(88,040)
Income before income taxes	56,186	133,225	38,835	(137,241)	91,005
Income tax benefit (expense)	6,155	(30,937)	—	—	(24,782)
Net income including non-controlling interests	62,341	102,288	38,835	(137,241)	66,223
Less: Net income attributable to non-controlling interests	—	3,882	26,459	(26,459)	3,882
Net income attributable to Oasis	$ 62,341	$ 98,406	$ 12,376	$ (110,782)	$ 62,341

Table of Contents

Condensed Consolidating Statement of Operations

	Three Months Ended September 30, 2017				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Revenues					
Oil and gas revenues	$—	$ 248,648	$ —	$ —	$ 248,648
Purchased oil and gas sales	—	21,195	—	—	21,195
Midstream revenues	—	15,828	2,939	—	18,767
Well services revenues	—	16,138	—	—	16,138
Total revenues	—	301,809	2,939	—	304,748
Operating expenses					
Lease operating expenses	—	45,334	—	—	45,334
Midstream operating expenses	—	3,621	680	—	4,301
Well services operating expenses	—	10,288	—	—	10,288
Marketing, transportation and gathering expenses	—	15,028	—	—	15,028
Purchased oil and gas expenses	—	21,701	—	—	21,701
Production taxes	—	21,052	—	—	21,052
Depreciation, depletion and amortization	—	132,035	254	—	132,289
Exploration expenses	—	854	—	—	854
Impairment	—	139	—	—	139
General and administrative expenses	6,775	14,212	381	—	21,368
Total operating expenses	6,775	264,264	1,315	—	272,354
Operating income (loss)	(6,775)	37,545	1,624	—	32,394
Other income (expense)					
Equity in earnings (loss) of subsidiaries	(13,599)	1,605	—	11,994	—
Net loss on derivative instruments	—	(54,310)	—	—	(54,310)
Interest expense, net of capitalized interest	(32,894)	(4,476)	(19)	—	(37,389)
Other income (expense)	2	(607)	—	—	(605)
Total other expense	(46,491)	(57,788)	(19)	11,994	(92,304)
Income (loss) before income taxes	(53,266)	(20,243)	1,605	11,994	(59,910)
Income tax benefit	12,052	6,794	—	—	18,846
Net income (loss) including non-controlling interests	(41,214)	(13,449)	1,605	11,994	(41,064)
Less: Net income attributable to non-controlling interests	—	150	1,112	(1,112)	150
Net income (loss) attributable to Oasis	$ (41,214)	$ (13,599)	$ 493	$ 13,106	$ (41,214)

Table of Contents

Condensed Consolidating Statement of Operations

	Nine Months Ended September 30, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Revenues					
Oil and gas revenues	$—	$1,212,235	$ —	$ —	$1,212,235
Purchased oil and gas sales	—	121,971	—	—	121,971
Midstream revenues	—	2,832	199,446	(113,827)	88,451
Well services revenues	—	46,344	—	—	46,344
Total revenues	—	1,383,382	199,446	(113,827)	1,469,001
Operating expenses					
Lease operating expenses	—	176,413	—	(38,957)	137,456
Midstream operating expenses	—	2,054	53,266	(30,995)	24,325
Well services operating expenses	—	32,352	—	—	32,352
Marketing, transportation and gathering expenses	—	92,164	—	(17,605)	74,559
Purchased oil and gas expenses	—	121,311	—	(60)	121,251
Production taxes	—	103,748	—	—	103,748
Depreciation, depletion and amortization	—	456,624	20,212	(11,017)	465,819
Exploration expenses	—	23,701	—	—	23,701
Impairment	—	384,228	—	—	384,228
General and administrative expenses	22,214	60,259	17,496	(8,940)	91,029
Total operating expenses	22,214	1,452,854	90,974	(107,574)	1,458,468
Gain on sale of properties	—	38,823	—	—	38,823
Operating income (loss)	(22,214)	(30,649)	108,472	(6,253)	49,356
Other income (expense)					
Equity in earnings (loss) of subsidiaries	(149,295)	107,849	—	41,446	—
Net loss on derivative instruments	—	(239,945)	—	—	(239,945)
Interest expense, net of capitalized interest	(98,417)	(18,591)	(608)	—	(117,616)
Loss on extinguishment of debt	(13,698)	—	—	—	(13,698)
Other income (expense)	—	161	(15)	—	146
Total other expense	(261,410)	(150,526)	(623)	41,446	(371,113)
Income (loss) before income taxes	(283,624)	(181,175)	107,849	35,193	(321,757)
Income tax benefit	26,351	49,040	—	—	75,391
Net income (loss) including non-controlling interests	(257,273)	(132,135)	107,849	35,193	(246,366)
Less: Net income attributable to non-controlling interests	—	10,907	73,075	(73,075)	10,907
Net income (loss) attributable to Oasis	$(257,273)	$(143,042)	$ 34,774	$ 108,268	$(257,273)

31

Table of Contents

Condensed Consolidating Statement of Operations

	Nine Months Ended September 30, 2017				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Revenues					
Oil and gas revenues	$—	$ 704,533	$ —	$ —	$ 704,533
Purchased oil and gas sales	—	56,917	—	—	56,917
Midstream revenues	—	46,000	2,939	—	48,939
Well services revenues	—	33,566	—	—	33,566
Total revenues	—	841,016	2,939	—	843,955
Operating expenses					
Lease operating expenses	—	133,871	—	—	133,871
Midstream operating expenses	—	10,211	680	—	10,891
Well services operating expenses	—	23,858	—	—	23,858
Marketing, transportation and gathering expenses	—	38,018	—	—	38,018
Purchased oil and gas expenses	—	57,683	—	—	57,683
Production taxes	—	60,322	—	—	60,322
Depreciation, depletion and amortization	—	383,992	254	—	384,246
Exploration expenses	—	4,010	—	—	4,010
Impairment	—	6,021	—	—	6,021
General and administrative expenses	21,374	45,415	381	—	67,170
Total operating expenses	21,374	763,401	1,315	—	786,090
Operating income (loss)	(21,374)	77,615	1,624	—	57,865
Other income (expense)					
Equity in earnings of subsidiaries	74,379	1,605	—	(75,984)	—
Net gain on derivative instruments	—	52,297	—	—	52,297
Interest expense, net of capitalized interest	(98,751)	(11,778)	(19)	—	(110,548)
Other income (expense)	2	(757)	—	—	(755)
Total other income (expense)	(24,370)	41,367	(19)	(75,984)	(59,006)
Income (loss) before income taxes	(45,744)	118,982	1,605	(75,984)	(1,141)
Income tax benefit (expense)	44,923	(44,453)	—	—	470
Net income (loss) including non-controlling interests	(821)	74,529	1,605	(75,984)	(671)
Less: Net income attributable to non-controlling interests	—	150	1,112	(1,112)	150
Net income (loss) attributable to Oasis	$ (821)	$ 74,379	$ 493	$ (74,872)	$ (821)

32

Table of Contents

Condensed Consolidating Statement of Cash Flows

	Nine Months Ended September 30, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities:					
Net income (loss) including non-controlling interests	$(257,273)	$(132,135)	$ 107,849	$ 35,193	$(246,366)
Adjustments to reconcile net income (loss) including non-controlling interests to net cash provided by (used in) operating activities:					
Equity in earnings (loss) of subsidiaries	149,295	(107,849)	—	(41,446)	—
Depreciation, depletion and amortization	—	456,624	20,212	(11,017)	465,819
Loss on extinguishment of debt	13,698	—	—	—	13,698
Gain on sale of properties	—	(38,823)	—	—	(38,823)
Impairment	—	384,228	—	—	384,228
Deferred income taxes	(26,351)	(49,067)	—	—	(75,418)
Derivative instruments	—	239,945	—	—	239,945
Equity-based compensation expenses	20,292	1,014	280	—	21,586
Deferred financing costs amortization and other	11,955	7,884	235	—	20,074
Working capital and other changes:					
Change in accounts receivable	(227,589)	(77,231)	8,747	234,798	(61,275)
Change in inventory	—	(12,076)	—	—	(12,076)
Change in prepaid expenses	(350)	864	682	—	1,196
Change in other current assets	—	1	—	—	1
Change in long-term inventory and other assets	—	(490)	—	—	(490)
Change in accounts payable, interest payable and accrued liabilities	(12,270)	278,481	18,895	(234,798)	50,308
Change in other liabilities	—	(406)	—	—	(406)
Net cash provided by (used in) operating activities	(328,593)	950,964	156,900	(17,270)	762,001
Cash flows from investing activities:					
Capital expenditures	—	(621,269)	(219,819)	—	(841,088)
Acquisitions	—	(579,886)	—	—	(579,886)
Proceeds from sale of properties	—	333,029	—	—	333,029
Costs related to sale of properties	—	(2,707)	—	—	(2,707)
Derivative settlements	—	(162,013)	—	—	(162,013)
Advances from joint interest partners	—	(1,038)	—	—	(1,038)
Net cash used in investing activities	—	(1,033,884)	(219,819)	—	(1,253,703)
Cash flows from financing activities:					
Proceeds from Revolving Credit Facilities	—	2,376,000	123,000	—	2,499,000
Principal payments on Revolving Credit Facilities	—	(1,924,000)	(35,000)	—	(1,959,000)
Repurchase of senior unsecured notes	(423,190)	—	—	—	(423,190)
Proceeds from issuance of senior unsecured convertible notes	400,000	—	—	—	400,000
Deferred financing costs	(7,058)	(261)	(331)	—	(7,650)
Purchases of treasury stock	(6,806)	—	—	—	(6,806)
Distributions to non-controlling interests	—	92,672	(103,065)	—	(10,393)

Investment in subsidiaries / capital contributions from parent	365,601	(465,293)	82,422	17,270	—
Other	38	(125)	—	—	(87)
Net cash provided by financing activities	328,585	78,993	67,026	17,270	491,874
Increase (decrease) in cash and cash equivalents	(8)	(3,927)	4,107	—	172
Cash and cash equivalents at beginning of period	178	15,659	883	—	16,720
Cash and cash equivalents at end of period	$ 170	$ 11,732	$ 4,990	$ —	$ 16,892

Table of Contents

Condensed Consolidating Statement of Cash Flows

	Nine Months Ended September 30, 2017				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities:					
Net income (loss) including non-controlling interests	$ (821)	$ 74,529	$ 1,605	$ (75,984)	$ (671)
Adjustments to reconcile net income (loss) including non-controlling interests to net cash provided by (used in) operating activities:					
Equity in earnings of subsidiaries	(74,379)	(1,605)	—	75,984	—
Depreciation, depletion and amortization	—	383,992	254	—	384,246
Impairment	—	6,021	—	—	6,021
Deferred income taxes	(44,923)	44,453	—	—	(470)
Derivative instruments	—	(52,297)	—	—	(52,297)
Equity-based compensation expenses	19,740	711	—	—	20,451
Deferred financing costs amortization and other	11,399	1,260	7	—	12,666
Working capital and other changes:					
Change in accounts receivable	115,996	(87,610)	(5,630)	(103,778)	(81,022)
Change in inventory	—	(235)	—	—	(235)
Change in prepaid expenses	(190)	1,013	—	—	823
Change in other current assets	—	276	—	—	276
Change in long-term inventory and other assets	—	(12,843)	—	—	(12,843)
Change in accounts payable, interest payable and accrued liabilities	(12,571)	(62,542)	3,617	103,778	32,282
Change in other current liabilities	—	(10,490)	—	—	(10,490)
Net cash provided by operating activities	14,251	284,633	(147)	—	298,737
Cash flows from investing activities:					
Capital expenditures	—	(443,649)	—	—	(443,649)
Proceeds from sale of properties	—	4,000	—	—	4,000
Derivative settlements	—	(804)	—	—	(804)
Advances from joint interest partners	—	(2,502)	—	—	(2,502)
Net cash used in investing activities	—	(442,955)	—	—	(442,955)
Cash flows from financing activities:					
Proceeds from Oasis Credit Facility	—	764,000	—	—	764,000
Principal payments on Oasis Credit Facility	—	(732,000)	—	—	(732,000)
Deferred financing costs	—	1,858	(1,954)	—	(96)
Proceeds from issuance of Oasis Midstream common units, net of offering costs	—	—	115,813	—	115,813
Purchases of treasury stock	(6,182)	—	—	—	(6,182)
Investment in subsidiaries / capital contributions from parent	(8,002)	121,714	(113,712)	—	—
Other	(55)	—	—	—	(55)
Net cash provided by (used in) financing activities	(14,239)	155,572	147	—	141,480
Increase (decrease) in cash and cash equivalents	12	(2,750)	—	—	(2,738)
Cash and cash equivalents at beginning of period	166	11,060	—	—	11,226
Cash and cash equivalents at end of period	$ 178	$ 8,310	$ —	$ —	$ 8,488

19. 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 previously disclosed.

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, 2017 ("2017 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 2017 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 midstream company, including ownership interests in a master limited partnership;
- owning and operating a well services company;
- infrastructure for produced and flowback water gathering and disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston and Delaware Basins and other regions in the United States;
- property acquisitions, including our recent acquisition of oil and gas properties in the Delaware 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;

Table of Contents

- developments in oil-producing and natural gas-producing countries;
- technology;
- uncertainty regarding future operating results;
- plans, objectives, expectations and intentions contained in this report that are not historical; and
- certain factors flagged elsewhere in this Form 10-Q.

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 onshore, unconventional oil and natural gas resources in the United States. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity has primarily been directed toward projects that we believe can provide us with repeatable successes in the Bakken and Three Forks formations. On February 14, 2018, we acquired approximately 22,000 net acres in the Delaware Basin from Forge Energy, LLC, representing our initial entry into the Delaware Basin (the "Permian Basin Acquisition"). The Permian Basin Acquisition more than doubled our core net inventory and allows us to further capitalize on our operational strengths. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct our exploration and production activities and own our proved and unproved oil and natural gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas regions of the Delaware Basin, respectively. We also operate a midstream services business through OMS Holdings LLC ("OMS") and a well services business through Oasis Well Services LLC ("OWS"), both of which are separate reportable business segments that are complementary to our primary development and production activities. The midstream services business is conducted by Oasis Midstream Partners LP ("OMP" or "Oasis Midstream"), which completed an initial public offering in September 2017. The Company owns the general partner and a majority of the outstanding units of OMP. The revenues and expenses related to work performed by OMS and OWS 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 a $1,600.0 million senior secured revolving credit facility among OPNA, as Borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "Oasis Credit Facility") and a $250.0 million senior secured revolving credit facility among OMP, as parent, OMP Operating LLC, a subsidiary of OMP, as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "OMP Credit Facility," and, together with the Oasis Credit Facility, our "Revolving Credit Facilities"), 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. 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. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives.

Table of Contents

Due to the geographic concentration of our oil and natural gas properties in the Williston Basin and Delaware 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. A substantial or extended decline in 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 and natural gas sales contracts with purchasers who have access to 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, 92% of our gross operated oil production and substantially all of our gross operated natural gas production are connected to these gathering systems, and our crude oil price differentials have improved to less than $3.00 per barrel primarily due to the additional takeaway capacity of the Dakota Access Pipeline of over 450,000 barrels per day.

Highlights:

- We produced 65,870 barrels of oil per day ("MBopd") in the third quarter of 2018, which represents a 27% increase over third quarter 2017;
- We produced 85,400 barrels of oil equivalent per day ("Boepd") in the third quarter of 2018 with an oil cut of 77%;
- Our oil differentials have decreased to $1.42 off of NYMEX West Texas Intermediate crude oil index price ("NYMEX WTI") in the third quarter of 2018, an approximate 22% decrease from the third quarter of 2017;
- Lease operating expenses per barrels of oil equivalent ("Boe") decreased over 17% to $6.18 per Boe in the third quarter of 2018 compared to $7.45 per Boe in the third quarter of 2017;
- We completed and placed on production 37 gross (24.4 net) operated wells, including 35 gross (22.4 net) operated wells in the Williston Basin and 2 gross (2.0 net) operated wells in the Delaware Basin, in the third quarter of 2018;
- Since the closing of the Permian Basin Acquisition, we successfully closed various acquisitions in Loving and Ward Counties, adjacent to our existing Delaware position. Combined, the acquisitions total to 1,600 net acres and approximately $22,000 per net acre, after backing out production value;
- We closed previously announced non-core divestitures that resulted in proceeds of $331 million during the third quarter of 2018; and
- Net cash provided by operating activities was $230.0 million for the three months ended September 30, 2018. Adjusted EBITDA, a non-GAAP financial measure, was $270.4 million for the three months ended September 30, 2018. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income (loss) including non-controlling interests and net cash provided by operating activities, see "Non-GAAP Financial Measures" below.

Table of Contents

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 purchased oil sales are derived from the sale of oil purchased through our marketing activities primarily for blending. Our midstream revenues are primarily derived from produced and flowback water pipeline transport, produced and flowback water disposal, natural gas gathering and processing, fresh water sales and crude oil gathering and transportation. Our well services revenues are derived from well services, product sales and equipment rentals. Substantially all of our midstream revenues and well services revenues are from services for third-party working interest owners in OPNA's operated wells. Intercompany revenues for work performed by OMS and OWS for OPNA's working interests are eliminated in consolidation and are therefore not included in midstream and well services revenues.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Change	2018	2017	Change
Operating results (in thousands)						
Revenues						
Oil revenues	$412,530	$221,004	$191,526	$1,097,171	$623,603	$473,568
Natural gas revenues	40,113	27,644	12,469	115,064	80,930	34,134
Purchased oil and gas sales	46,356	21,195	25,161	121,971	56,917	65,054
Midstream revenues	31,187	18,767	12,420	88,451	48,939	39,512
Well services revenues	16,262	16,138	124	46,344	33,566	12,778
Total revenues	$546,448	$304,748	$241,700	$1,469,001	$843,955	$625,046
Production data						
Oil (MBbl)	6,060	4,768	1,292	16,862	13,552	3,310
Natural gas (MMcf)	10,781	7,894	2,887	30,825	23,131	7,694
Oil equivalents (MBoe)	7,857	6,083	1,774	21,999	17,408	4,591
Average daily production (Boepd)	85,400	66,125	19,275	80,583	63,764	16,819
Average sales prices						
Oil, without derivative settlements (per Bbl)	$68.07	$46.35	$21.72	$65.07	$46.02	$19.05
Oil, with derivative settlements (per Bbl)(1)	57.25	47.93	9.32	55.40	45.90	9.50
Natural gas, without derivative settlements (per Mcf)(2)	3.72	3.50	0.22	3.73	3.50	0.23
Natural gas, with derivative settlements (per Mcf)(1)(2)	3.76	3.58	0.18	3.77	3.53	0.24

(1) Realized prices include gains or losses on cash settlements for our commodity derivatives, which do not qualify for or 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.

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

Table of Contents

Three months ended September 30, 2018 as compared to three months ended September 30, 2017

Oil and gas revenues. Our oil and gas revenues increased $204.0 million, or 82%, to $452.6 million during the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. This increase was primarily driven by a $105.3 million increase due to the higher oil and natural gas sales prices, coupled with a $98.7 million increase driven by higher oil and natural gas production amounts sold during the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. Average oil sales prices, without derivative settlements, increased by $21.72 per barrel to an average of $68.07 per barrel, and average natural gas sales prices, which includes the value for natural gas and natural gas liquids and is without derivative settlements, increased by $0.22 per Mcf to an average of $3.72 per Mcf for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. Average daily production sold increased by 19,275 Boepd to 85,400 Boepd during the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. The increase in average daily production sold was primarily a result of our 90.8 total net well completions in the Williston Basin during the twelve months ended September 30, 2018 and the Permian Basin Acquisition, which was completed on February 14, 2018.

Purchased oil and gas sales. Purchased oil and gas sales, which consist primarily of the sale of crude oil purchased for blending at our crude oil terminal or in an attempt to make a profit. Purchased oil and gas sales increased $25.2 million to $46.4 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017, primarily due to higher volumes purchased and sold driven by increased market opportunities in the Williston Basin and in the Delaware Basin.

Midstream revenues. Midstream revenues increased $12.4 million to $31.2 million during the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. This increase was primarily driven by a $5.9 million increase related to higher natural gas volumes gathered, compressed and processed, coupled with a $5.8 million increase related to higher water service volumes driven by an increase in producing wells and a $0.6 million increase related to higher oil volumes gathered, stabilized and transported.

Well services revenues. Our well services revenues increased by $0.1 million to $16.3 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017.

Nine months ended September 30, 2018 as compared to nine months ended September 30, 2017

Oil and gas revenues. Our oil and gas revenues increased $507.7 million, or 72%, to $1,212.2 million during the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. The higher oil and natural gas sales prices increased revenues by $263.6 million, coupled with a $244.1 million increase due to the higher oil and natural gas production amounts sold during the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. Average oil sales prices, without derivative settlements, increased by $19.05 per barrel to an average of $65.07 per barrel, and average natural gas sales prices, which includes the value for natural gas and natural gas liquids and is without derivative settlements, increased by $0.23 per Mcf to an average of $3.73 per Mcf for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. Average daily production sold increased by 16,819 Boe per day to 80,583 Boe per day during the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. The increase in average daily production sold was primarily a result of our 90.8 total net well completions in the Williston Basin during the twelve months ended September 30, 2018 and the Permian Basin Acquisition, which was completed on February 14, 2018.

Purchased oil and gas sales. Purchased oil and gas sales, which consist primarily of the sale of crude oil purchased for blending at our crude oil terminal or in an attempt to make a profit. Purchased oil and gas sales increased $65.1 million to $122.0 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 due to higher volumes purchased and sold driven by increased market opportunities in the Williston Basin and in the Delaware Basin.

Midstream revenues. Midstream revenues were $88.5 million for the nine months ended September 30, 2018, which was a $39.5 million increase period over period. This increase was driven by an $19.5 million increase related to higher natural gas volumes gathered, compressed and processed, coupled with a $16.0 million increase related to higher water service volumes driven by an increase in producing wells and a $3.8 million increase related to higher oil volumes gathered, stabilized and transported.

Well services revenues. In 2017, we increased the pace of our well completions and added a second fracturing fleet as well as third party crews. As a result, our well services revenues increased by $12.7 million to $46.3 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017, which was due to an $11.0 million increase in well completion revenue due to the increased activity as a result of adding the second fracturing fleet in the third quarter of 2017, coupled with a $1.2 million increase in equipment rentals and a $0.4 million increase in product sales to third parties.

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,		
	2018	2017	Change	2018	2017	Change
	(In thousands, except per Boe of production)					
Operating expenses						
Lease operating expenses	$48,534	$45,334	$3,200	$137,456	$133,871	$3,585
Midstream operating expenses	8,652	4,301	4,351	24,325	10,891	13,434
Well services operating expenses[(1)]	11,405	10,288	1,117	32,352	23,858	8,494
Marketing, transportation and gathering expenses	30,713	15,028	15,685	74,559	38,018	36,541
Purchased oil and gas expenses	46,088	21,701	24,387	121,251	57,683	63,568
Production taxes	38,722	21,052	17,670	103,748	60,322	43,426
Depreciation, depletion and amortization	162,984	132,289	30,695	465,819	384,246	81,573
Exploration expenses	22,315	854	21,461	23,701	4,010	19,691
Impairment	—	139	(139)	384,228	6,021	378,207
General and administrative expenses[(1)]	34,859	21,368	13,491	91,029	67,170	23,859
Total operating expenses	404,272	272,354	131,918	1,458,468	786,090	672,378
Gain on sale of properties	36,869	—	36,869	38,823	—	38,823
Operating income	179,045	32,394	146,651	49,356	57,865	(8,509)
Other income (expense)						
Net gain (loss) on derivative instruments	(48,544)	(54,310)	5,766	(239,945)	52,297	(292,242)
Interest expense, net of capitalized interest	(39,560)	(37,389)	(2,171)	(117,616)	(110,548)	(7,068)
Loss on extinguishment of debt	(47)	—	(47)	(13,698)	—	(13,698)
Other income (expense)	111	(605)	716	146	(755)	901
Total other expense	(88,040)	(92,304)	4,264	(371,113)	(59,006)	(312,107)
Income (loss) before income taxes	91,005	(59,910)	150,915	(321,757)	(1,141)	(320,616)
Income tax benefit (expense)	(24,782)	18,846	(43,628)	75,391	470	74,921
Net income (loss) including non-controlling interests	66,223	(41,064)	107,287	(246,366)	(671)	(245,695)
Less: Net income attributable to non-controlling interests	3,882	150	3,732	10,907	150	10,757
Net income (loss) attributable to Oasis	$62,341	$(41,214)	$103,555	$(257,273)	$(821)	$(256,452)
Costs and expenses (per Boe of production)						
Lease operating expenses	$6.18	$7.45	$(1.27)	$6.25	$7.69	$(1.44)
Marketing, transportation and gathering expenses	3.91	2.47	1.44	3.39	2.18	1.21
Production taxes	4.93	3.46	1.47	4.72	3.47	1.25
Depreciation, depletion and amortization	20.74	21.75	(1.01)	21.17	22.07	(0.90)
General and administrative expenses[(1)]	4.44	3.51	0.93	4.14	3.86	0.28

(1) For the three and nine months ended September 30, 2017, well services operating expenses have been adjusted to include $1.2 million and $2.7 million, respectively, for certain well services direct field labor compensation expenses which were previously recognized in general and administrative expenses on our Condensed Consolidated Statements of Operations.

Three months ended September 30, 2018 as compared to three months ended September 30, 2017

Lease operating expenses. Lease operating expenses increased $3.2 million to $48.5 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. The increase was primarily due to higher costs associated with operating an increased number of producing wells as a result of our well completions and the Permian Basin Acquisition, coupled with an increase in produced and flowback water disposal volumes being transported on OMS pipelines and injected in OMS produced and flowback water disposal wells and higher costs associated with operating an increased number of producing wells during the three months ended September 30, 2018. Utilizing our own infrastructure for produced and flowback water disposal enables us to lower operating costs through increased operational efficiency. Lease operating expenses per Boe decreased quarter over quarter from $7.45 per Boe to $6.18 per Boe primarily due to higher production volumes period over period.

Midstream operating expenses. Midstream operating expenses represent third-party working interest owners' share of operating expenses incurred by OMS, as well as operating expenses related to midstream services provided to third parties. The $4.4 million increase quarter over quarter was primarily related to a $2.5 million increase in gas gathering, compression and processing expenses driven by increased production, coupled with a $1.4 million increase related to higher water service volumes driven by an increase in producing wells.

Well services operating expenses. Well services operating expenses represent third-party working interest owners' share of completion service costs, cost of goods sold and operating expenses incurred by OWS. The $1.1 million increase quarter over quarter was primarily attributable to increased well completion activity.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $15.7 million, or $1.44 per Boe, for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017, which was primarily attributable to higher oil gathering and transportation expenses related to an increase in volumes being transported on the Dakota Access Pipeline, which started in the second quarter of 2017, to market our equity barrels. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis increased to $3.84 during the three months ended September 30, 2018 as compared to $2.50 during the three months ended September 30, 2017 primarily due to the higher aforementioned costs.

Purchased oil and gas expenses. Purchased oil and gas expenses, which represent the crude oil purchased primarily for blending at our crude oil terminal or in attempt to make a profit, increased $24.4 million to $46.1 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017 primarily due to higher volumes purchased and sold driven by increased market opportunities in the Williston Basin and in the Delaware Basin.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 8.6% and 8.5% for the three months ended September 30, 2018 and 2017, respectively. The production tax rate increased quarter over quarter primarily due to a higher oil production mix, coupled with the addition of Delaware Basin assets following the Permian Basin Acquisition in February 2018 which bear a lower average production tax rate than Williston Basin assets. North Dakota's natural gas production tax is $0.0705 per Mcf, while its crude oil tax structure is based on a 5% production tax and a 5% oil extraction tax, resulting in a combined tax rate of 10% of crude oil revenues.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $30.7 million to $163.0 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. This increase in DD&A expense quarter over quarter was a result of increased production from our wells completed during the three months ended September 30, 2018, coupled with the Permian Basin Acquisition, offset by a decrease in the DD&A rate to $20.74 per Boe for the three months ended September 30, 2018 as compared to $21.75 per Boe for the three months ended September 30, 2017. The decrease in the DD&A rate was primarily due to higher recoverable reserves as a result of higher oil prices and the removal of the divested non-core oil and gas properties (see Note 10 - Divestitures), coupled with lower costs and higher estimated ultimate recoveries on our more recently completed wells.

Exploration expenses. Exploration expenses increased $21.5 million to $22.3 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017, primarily due to higher write-off of costs of $20.7 million related to exploratory well locations that are no longer in our current development plan.

General and administrative expenses (“G&A”). Our G&A increased $13.5 million to $34.9 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017. E&P G&A increased $12.6 million quarter over quarter primarily due to costs related to the Permian Basin Acquisition and increased employee compensation expenses as a result of organizational growth. OMS G&A increased $1.0 million quarter over quarter primarily due to increased employee compensation expenses as a result of organizational growth. OWS G&A decreased $0.1 million to $1.6 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017.

Table of Contents

Gain on sale of properties. For the three months ended September 30, 2018, we recognized a $36.9 million gain primarily related to three separate divestitures to sell certain non-core oil and gas properties in the Williston Basin (see Note 10 - Divestitures). No gain or loss on sale of properties was recorded for the three months ended September 30, 2017.

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil and gas price changes, we incurred a $48.5 million net loss on derivative instruments, including net cash settlement payments of $65.2 million, for the three months ended September 30, 2018 and a $54.3 million net loss on derivative instruments, including net cash settlement receipts of $8.1 million for the three months ended September 30, 2017. 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.

Interest expense. Interest expense increased $2.2 million to $39.6 million for the three months ended September 30, 2018 as compared to the three months ended September 30, 2017 primarily due to a $3.8 million increase in interest expense related to our borrowings under our Revolving Credit Facilities. This increase in interest expense was partially offset by an increase in capitalized interest of $1.4 million due to higher costs for work in progress assets. For the three months ended September 30, 2018, the weighted average debts outstanding under the Oasis Credit Facility and the OMP Credit Facility were $561.3 million and $172.9 million, respectively, and the weighted average interest rates incurred on the outstanding borrowings were 3.9% and 3.8%, respectively. For the three months ended September 30, 2017, the weighted average debt outstanding under the Oasis Credit Facility was $484.9 million, and the weighted average interest rate incurred on the outstanding borrowings were 3.0%. Interest capitalized during the three months ended September 30, 2018 and 2017 was $4.5 million and $3.1 million, respectively, which will be amortized over the life of the related assets.

Income tax benefit (expense). Our income tax expense for the three months ended September 30, 2018 was recorded at 27.2% of pre-tax income and the income tax benefit for the three months ended September 30, 2017 was recorded at 31.5% of pre-tax loss. Our effective tax rate for the three months ended September 30, 2018 was lower than the effective tax rate for the three months ended September 30, 2017 primarily due to the change in the corporate tax rate under the Tax Cuts and Jobs Act, partially offset by the impacts of non-deductible executive compensation and equity-based compensation windfalls in 2018 as compared to equity-based compensation shortfalls in 2017.

Nine months ended September 30, 2018 as compared to nine months ended September 30, 2017

Lease operating expenses. Lease operating expenses increased $3.6 million to $137.5 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. The increase was primarily due to higher costs associated with operating an increased number of producing wells as a result of our well completions and the Permian Basin Acquisition, coupled with an increase in produced and flowback water disposal volumes being transported and injected. These costs were partially offset by lower workover costs during the nine months ended September 30, 2018. Lease operating expenses per Boe decreased from $7.69 per Boe to $6.25 per Boe primarily due to higher production volumes period over period.

Midstream operating expenses. Midstream operating expenses represent third-party working interest owners' share of operating expenses incurred by OMS, as well as operating expenses related to midstream services provided to third parties. The $13.4 million increase for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 was primarily related to the $6.8 million increase in gas gathering, compression and processing expenses driven by increased production, coupled with a $4.7 million increase related to higher water service volumes driven by an increase in producing wells and a $1.8 million increase related to higher oil volumes gathered, stabilized and transported.

Well services operating expenses. Well services operating expenses represent third-party working interest owners' share of completion service costs, cost of goods sold and operating expenses incurred by OWS. The $8.5 million increase for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 was primarily attributable to increased well completion activity, coupled with increased direct labor, trucking and maintenance expenses due to the addition of a second fracturing fleet in the third quarter of 2017.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $36.5 million period over period, or a $1.21 increase per Boe, which was primarily attributable to higher oil gathering and transportation expenses related to increased throughput on the Dakota Access Pipeline, which began operations in the second quarter of 2017, and our oil gathering system, which has been ramping up throughputs since it began operations in the second half of 2016. In addition, natural gas gathering and processing expenses increased due to additional well connections on OMS infrastructure and our natural gas processing plant, which has been ramping up throughputs since it began operations in the second half of 2016. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis increased to $3.36 for the nine months ended September 30, 2018 as compared to $2.16 for the nine months ended September 30, 2017 primarily due to the higher aforementioned costs.

Table of Contents

Purchased oil and gas expenses. Purchased oil and gas expenses, which represent the crude oil purchased primarily for blending at our crude oil terminal or in attempt to make a profit, increased $63.6 million to $121.3 million for the nine months ended September 30, 2018 as compared to nine months ended September 30, 2017 primarily due to higher volumes purchased and sold driven by increased market opportunities in the Williston Basin and in the Delaware Basin.
Production taxes. The production tax rate remained relatively flat period over period. Our production taxes as a percentage of oil and natural gas sales was 8.6% for the nine months ended September 30, 2018 and 2017, respectively. North Dakota's natural gas production tax is $0.0705 per Mcf, while its crude oil tax structure is based on a 5% production tax and a 5% oil extraction tax, resulting in a combined tax rate of 10% of crude oil revenues.
Depreciation, depletion and amortization. DD&A expense increased $81.6 million to $465.8 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017. The increase in DD&A expense was primarily due to increased production from our wells completed during the nine months ended September 30, 2018, coupled with the Permian Basin Acquisition. This increase was partially offset by a decrease in the average DD&A rate to $21.17 per Boe for the nine months ended September 30, 2018 as compared to $22.07 per Boe for the nine months ended September 30, 2017. The decrease in the DD&A rate was primarily due to higher recoverable reserves as a result of higher oil prices and the removal of the divested non-core oil and gas properties (see Note 10 - Divestitures), coupled with lower costs and higher estimated ultimate recoveries on our more recently completed wells.
Exploration expenses. Exploration expenses increased $19.7 million to $23.7 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017, primarily due to write-off of costs of $20.7 million related to exploratory well locations that are no longer in our current development plan, offset by lower geological and geophysical expenses and delay rentals.
Impairment. During the nine months ended September 30, 2018, we recorded an impairment loss of $383.4 million to adjust the carrying value of our properties for the Foreman Butte Divestiture to their estimated fair value, determined based on the expected sales price less costs to sell (see Note 10 - Divestitures). There were no similar impairment charges related to these assets recorded during the nine months ended September 30, 2017. As a result of periodic assessments of our unproved properties not held-by-production, we recorded an impairment loss on our unproved oil and natural gas properties of $0.9 million and $6.0 million for the nine months ended September 30, 2018 and 2017, respectively, related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration.
General and administrative expenses. Our G&A expenses increased $23.8 million for the nine months ended September 30, 2018 from $67.2 million for the nine months ended September 30, 2017. E&P G&A increased $19.6 million period over period primarily due to increased costs related to the Permian Basin Acquisition and increased employee compensation expenses as a result of organizational growth. OMS G&A increased $4.2 million period over period primarily due to expenses incurred related to the initial public offering of OMP, coupled with increased employee compensation as a result of organizational growth. OWS G&A was $4.7 million and $4.6 million for the nine months ended September 30, 2018 and 2017, respectively.
Gain on sale of properties. For the nine months ended September 30, 2018, we recognized a $38.8 million gain primarily related to three separate divestitures to sell certain non-core oil and gas properties in the Williston Basin (see Note 10 - Divestitures). No gain or loss on sale of properties was recorded for the nine months ended September 30, 2017.
Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil and gas price changes, we incurred a $239.9 million net loss on derivative instruments, including net cash settlement payments of $162.0 million, for the nine months ended September 30, 2018, and a $52.3 million net gain on derivative instruments, including net cash settlement payments of $0.8 million, for the nine months ended September 30, 2017. 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.

Interest expense. Interest expense increased $7.1 million to $117.6 million for the nine months ended September 30, 2018 as compared to the nine months ended September 30, 2017 primarily due to a $11.2 million increase in interest expense related to our borrowings under our Revolving Credit Facilities and an increase in debt discount amortization related to our senior unsecured convertible notes. These increases in interest expense were partially offset by an increase in capitalized interest of $4.4 million due to higher costs for work in progress assets and a decrease in interest expense related to the repurchase of an aggregate principal amount of $390.6 million of outstanding senior unsecured notes and issuance of $400.0 million senior unsecured notes due 2026 at a lower interest rate of 6.25% in May 2018. For the nine months ended September 30, 2018, the weighted average debts outstanding under the Oasis Credit Facility and the OMP Credit Facility were $552.7 million and $142.8 million, respectively, and the weighted average interest rates incurred on the outstanding borrowings were 3.8% and 3.7%, respectively. For the nine months ended September 30, 2017, the weighted average debt outstanding under the Oasis Credit Facility was $436.2 million, and the weighted average interest rate incurred on the outstanding borrowings thereunder was 2.8%. We capitalized $13.2 million and $8.8 million of interest costs for the nine months ended September 30, 2018 and 2017, respectively, which will be amortized over the life of the related assets.

Loss on extinguishment of debt. During the nine months ended September 30, 2018, we repurchased an aggregate principal amount of $413.5 million of our outstanding senior unsecured notes for an aggregate cost of $423.1 million, including fees. For the nine months ended September 30, 2018, we recognized a pre-tax loss related to the repurchase of $13.7 million, which included unamortized deferred financing costs write-offs of $4.0 million. During the nine months ended September 30, 2017, we did not repurchase any portion of our outstanding senior unsecured notes.

Income tax benefit. Our income tax benefit for the nine months ended September 30, 2018 and 2017 was recorded at 23.4% and 41.2% of pre-tax loss, respectively. Our effective tax rate for the nine months ended September 30, 2018 was lower than the effective tax rate for the nine months ended September 30, 2017 primarily due to the change in the corporate tax rate under the Tax Cuts and Jobs Act, the impact of non-deductible executive compensation and equity-based compensation shortfalls in 2018 as compared to equity-based compensation windfalls in 2017, partially offset by the portion of OMP's earnings attributable to the non-controlling public limited partners, which are not taxable to us, and a change in the blended state rate at which our deferred taxes are recorded.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report have been proceeds from our Notes (as defined below), borrowings under our Revolving Credit Facilities, 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 cash have been for the acquisition and development of oil and natural gas properties and midstream infrastructure, payment of operating and general and administrative costs, interest payments on outstanding debt and repurchases of Senior Notes. We continually monitor potential capital sources, including equity and debt financings and potential asset monetization opportunities, 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, 2018 and 2017 are presented below:

	Nine Months Ended September 30,	
	2018	2017
	(In thousands)	
Net cash provided by operating activities	$762,001	$298,737
Net cash used in investing activities	(1,253,703)	(442,955)
Net cash provided by financing activities	491,874	141,480
Increase (decrease) in cash and cash equivalents	$172	$(2,738)

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. For additional information on the impact of changing prices on our financial position, see Item 3. "Quantitative and Qualitative Disclosures about Market Risk" below.

Cash flows provided by operating activities

Net cash provided by operating activities was $762.0 million and $298.7 million for the nine months ended September 30, 2018 and 2017, respectively. The change in cash flows from operating activities for the period ended September 30, 2018 as compared to 2017 was primarily the result of the 41% increase in realized prices for oil and the 7% increase in realized prices for natural gas, coupled with our 26% increase in oil and natural gas production.

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 $333.2 million at September 30, 2018 primarily due to increases in our current liabilities, primarily due to the impact of increases in our accrued liabilities for drilling and development costs coupled with increases in the forward commodity price curve on our short-term derivative instruments. As of September 30, 2018, we had $914.9 million of liquidity available, including $16.9 million in cash and cash equivalents and $898.0 million of aggregate unused borrowing capacity available under our

Revolving Credit Facilities. At September 30, 2017, we had a working capital deficit of $99.3 million.

Table of Contents

Cash flows used in investing activities
Net cash used in investing activities was $1,253.7 million and $443.0 million during the nine months ended September 30, 2018 and 2017, respectively. Net cash used in investing activities during the nine months ended September 30, 2018 was primarily attributable to $841.1 million in capital expenditures primarily for drilling and development costs, coupled with $579.9 million in acquisitions primarily for the Permian Basin Acquisition and the Other Delaware Acquisition. Net cash used in investing activities during the nine months ended September 30, 2017 was primarily attributable to $443.6 million in capital expenditures primarily for drilling and development costs.
Our capital expenditures are summarized in the following table:

	Three Months Ended			Nine Months Ended September 30, 2018
	March 31, 2018	June 30, 2018	September 30, 2018	
	(In thousands)			
Capital expenditures:				
E&P	$176,937	$280,008	$247,838	$704,783
Well services	4,262	939	1,089	6,290
Other capital expenditures(1)	6,287	5,434	6,446	18,167
Total capital expenditures before acquisitions and midstream	187,486	286,381	255,373	729,240
Midstream(2)	88,794	68,626	61,339	218,759
Total capital expenditures before acquisitions	276,280	355,007	316,712	947,999
Acquisitions	890,948	3,527	55,631	950,106
Total capital expenditures(3)	$1,167,228	$358,534	$372,343	$1,898,105

(1) Other capital expenditures include such items as administrative capital and capitalized interest.
(2) Midstream CapEx attributable to OMP was $16.7 million and $85.3 million for the three and nine months ended September 30, 2018, respectively.
(3) Total capital expenditures reflected in the table above differs from the amounts for capital expenditures and acquisitions shown in the statements of cash flows in our condensed consolidated financial statements because amounts reflected in this table include changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statements of cash flows are presented on a cash basis.

Our total 2018 capital expenditure plan is approximately $1,230 million to $1,275 million, which includes approximately $900 million to $930 million for E&P capital expenditures, including approximately $785 million to $805 million focused in the Williston Basin and approximately $115 million to $125 million focused in the Delaware Basin, approximately $290 million to $305 million for infrastructure, midstream and well services equipment capital expenditures and approximately $40 million of other capital expenditures, including capitalized interest and administrative capital.
While we have planned approximately $1,230 million to $1,275 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 acquire additional acreage, our capital expenditures may be higher than planned. We believe that cash on hand, including cash flows from operating activities and availability under our Revolving Credit Facilities, should be sufficient to fund our 2018 capital expenditure plan and to meet our future obligations. However, because the operated wells funded by our 2018 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 plan may further be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil prices decline substantially or for an extended period of time, we could defer a significant portion of our planned 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 $491.9 million and $141.5 million for the nine months ended September 30, 2018 and 2017, respectively. For the nine months ended September 30, 2018, cash provided by financing activities was primarily due to proceeds from the borrowings under our Revolving Credit Facilities and proceeds from the issuance of senior unsecured notes, partially offset by principal payments on our Revolving Credit Facilities and the repurchase of senior unsecured notes. Net cash provided by financing activities during the nine months ended September 30, 2017 was primarily due to proceeds from the borrowings under our Oasis Credit Facility, partially offset by principal payments on our Oasis Credit Facility. For both the nine months ended September 30, 2018 and 2017, 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.

Senior secured revolving line of credit. We have the Oasis Credit Facility with an overall senior secured line of credit of $2,500.0 million as of September 30, 2018. The Oasis 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. The maturity date of the Oasis Credit Facility is April 13, 2020. On February 26, 2018, we entered into an amendment to the Oasis Credit Facility, resulting in the aggregate elected commitment being increased from $1,150.0 million to $1,350.0 million and two new lenders being added to the bank group. On April 19, 2018, the lenders under the Oasis Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2018, resulting in us entering into the Twelfth Amendment to the Second Amended and Restated Credit Agreement to the Oasis Credit Facility, which (i) reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, (ii) removed the legacy anti-cash hoarding provisions, (iii) reduced the coverage threshold with respect to mortgaged properties and (iv) amended the asset sale covenant to give us additional flexibility to trade oil and gas properties. In addition, in connection with such amendment, OP Permian became a guarantor under the Oasis Credit Facility.

On October 16, 2018, we entered into a third amended and restated credit agreement (the “Third Amended Credit Facility”). In connection with entry into the Third Amended Credit Facility, the semi-annual redetermination of our borrowing base was completed on October 16, 2018, which reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, and the overall credit facility increased from $2,500.0 million to $3,000.0 million. Pursuant to the Third Amended Credit Facility, the credit facility was extended from April 2020 to October 2023, provided that our 2022 and 2023 Senior Notes are retired or refinanced 90 days prior to their respective maturities. All other significant rates, terms and conditions of the Amended Credit Facility remained the same. The next redetermination of the Oasis Credit Facility’s borrowing base is scheduled for April 1, 2019.

As of September 30, 2018, we had $522.0 million of borrowings at a weighted average interest rate of 3.9% and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing base committed capacity of $814.0 million.

The Oasis 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 Oasis Credit Facility) to consolidated Interest Expense (as defined in the Oasis Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter;
- a requirement that we maintain a Current Ratio (as defined in the Oasis Credit Facility) of consolidated current assets (including unused borrowing base committed capacity and with exclusions as described in the Oasis Credit Facility)

to consolidated current liabilities (with exclusions as described in the Oasis Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter; and

- if the Aggregate Elected Commitment Amounts (as defined in the Oasis Credit Facility) exceed 85% of the effective borrowing base ("Trigger"), we are required to maintain a ratio of total debt (as defined in the Oasis Credit Facility) to consolidated EBITDAX (as defined in the Oasis Credit Facility) (the "Leverage Ratio"). The Leverage Ratio will be first tested during the quarter in which the Trigger occurs. The Leverage Ratio shall continue to be tested as long as the Aggregate Elected Commitment Amounts exceed 85% of the effective

Table of Contents

borrowing base, and shall not exceed 4.25 to 1.00 for the first two quarters and 4.00 to 1.00 for each quarter thereafter. The Oasis 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 Oasis Credit Facility to be immediately due and payable. We were in compliance with the financial covenants of the Oasis Credit Facility as of September 30, 2018. Given the possible fluctuation in commodity prices, we continue to closely monitor our financial covenants and do not anticipate a covenant violation in the next twelve months.

OMP Operating LLC revolving line of credit. Through our majority ownership of OMP, we have access to the OMP Credit Facility. The OMP Credit Facility has a maturity date of September 25, 2022 and is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. On August 27, 2018, OMP entered into an amendment to its revolving credit facility to the OMP Credit Facility in order to (i) increase the aggregate amount of commitments from $200.0 million to $250.0 million, (ii) provide for the ability to further increase commitments and (iii) add six new lenders to the bank group. The OMP Credit Facility is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. The OMP Credit Facility includes a letter of credit sublimit of $10.0 million and a swingline loans sublimit of $10.0 million. The borrowing capacity on the OMP Credit Facility may be increased up to $400.0 million, subject to certain conditions.

At September 30, 2018, we had $166.0 million of borrowings outstanding under the OMP Credit Facility. As of September 30, 2018, the weighted average interest rate on borrowings under the OMP Credit Facility was 4.0%.

The OMP Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (i) consolidated total leverage ratio, (ii) consolidated senior secured leverage ratio and (iii) consolidated interest coverage ratio (each covenant as described in the OMP Credit Facility). All obligations of OMP Operating LLC, as the borrower under the OMP Credit Facility, are unconditionally guaranteed on a joint and several basis by OMP, OMP Operating LLC and Bighorn DevCo LLC. OMP Operating LLC was in compliance with the financial covenants of the OMP Credit Facility at September 30, 2018.

Senior unsecured notes. As of September 30, 2018, our long-term debt includes outstanding senior unsecured note obligations of $1,739.4 million for senior unsecured notes with maturities ranging from November 2021 to May 2026 and coupons ranging from 6.25% to 6.875% (the “Senior Notes”). 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.

On May 14, 2018, we completed our offering of $400.0 million in aggregate principal amount of our 6.25% senior unsecured notes due 2026 (the “2026 Notes”). We used the net proceeds of $394.4 million from the 2026 Notes to fund the repurchase of certain outstanding senior notes (the “Tender Offers”).

On May 25, 2018, we completed the Tender Offers, and as a result of the Tender Offers, we repurchased an aggregate principal amount of $390.6 million of our outstanding Senior Notes, consisting of $31.3 million principal amount of our 7.25% senior unsecured notes due 2019 (the “2019 Notes”), $323.7 million principal amount of our 6.50% senior unsecured notes due 2021 and $35.6 million principal amount of our 6.875% senior unsecured notes due 2022, for an aggregate cost of $402.0 million, including accrued interest and fees.

On May 29, 2018, we paid $23.0 million to redeem all of the remaining outstanding 2019 Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the 2019 Notes. We financed the redemption with borrowings under the Oasis Credit Facility. As a result of the Tender Offers and the redemption, we recognized a pre-tax loss of $13.7 million, which was net of unamortized deferred financing costs write-offs of $4.0 million, and is reflected in loss on extinguishment of debt in our Condensed Consolidated Statements of Operations for the nine months ended September 30, 2018. As of September 30, 2018, no 2019 Notes remained outstanding.

The indentures governing the Senior 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 Senior 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. We were in compliance with the terms of the indentures for the Senior Notes as of September 30, 2018.

Senior unsecured convertible notes. At September 30, 2018, we had $300.0 million of 2.625% senior unsecured convertible notes due September 2023 (the “Senior Convertible Notes”). 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 our 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 (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, 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 our 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, we 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, 2018, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met. In addition, we were in compliance with the terms of the indentures for the Senior Convertible Notes as of September 30, 2018.

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.

Non-GAAP Financial Measures

Cash Interest, Adjusted EBITDA, Free Cash Flow, Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis 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) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis 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.

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,	
	2018	2017	2018	2017
	(In thousands)			
Interest expense	$39,560	$37,389	$117,616	$110,548
Capitalized interest	4,531	3,137	13,209	8,773
Amortization of deferred financing costs	(1,813)	(1,729)	(5,511)	(5,128)
Amortization of debt discount	(2,852)	(2,591)	(8,201)	(7,426)
Cash Interest	$39,426	$36,206	$117,113	$106,767

Table of Contents

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 nonrecurring 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 ability to generate cash from our business operations without regard to our financing methods or capital structure coupled with our ability to maintain compliance with our debt covenants.

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.

The following table presents reconciliations of the GAAP financial measures of net income (loss) including non-controlling interests 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:

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Net income (loss) including non-controlling interests	$66,223	$(41,064)	$(246,366)	$(671)
Gain on sale of properties	(36,869)	—	(38,823)	—
Loss on extinguishment of debt	47	—	13,698	—
Net (gain) loss on derivative instruments	48,544	54,310	239,945	(52,297)
Derivative settlements[1]	(65,190)	8,095	(162,013)	(804)
Interest expense, net of capitalized interest	39,560	37,389	117,616	110,548
Depreciation, depletion and amortization	162,984	132,289	465,819	384,246
Impairment	—	139	384,228	6,021
Exploration expenses	22,315	854	23,701	4,010
Equity-based compensation expenses	7,456	6,628	21,586	20,451
Income tax (benefit) expense	24,782	(18,846)	(75,391)	(470)
Other non-cash adjustments	574	(208)	557	491
Adjusted EBITDA	270,426	179,586	744,557	471,525
Adjusted EBITDA attributable to non-controlling interests	5,194	190	14,647	190
Adjusted EBITDA attributable to Oasis	265,232	179,396	729,910	471,335
Cash Interest	(39,426)	(36,206)	(117,113)	(106,767)
Capital expenditures[2]	(372,343)	(240,373)	(1,898,105)	(523,143)
Capitalized interest	4,531	3,137	13,209	8,773
Free Cash Flow	$(142,006)	$(94,046)	$(1,272,099)	$(149,802)
Net cash provided by operating activities	$229,985	$88,876	$762,001	$298,737
Derivative settlements[1]	(65,190)	8,095	(162,013)	(804)
Interest expense, net of capitalized interest	39,560	37,389	117,616	110,548
Exploration expenses	22,315	854	23,701	4,010
Deferred financing costs amortization and other	(9,556)	(3,795)	(20,074)	(12,666)
Current tax expense	(93)	—	27	—
Changes in working capital	52,831	48,375	22,742	71,209
Other non-cash adjustments	574	(208)	557	491
Adjusted EBITDA	270,426	179,586	744,557	471,525
Adjusted EBITDA attributable to non-controlling interests	5,194	190	14,647	190
Adjusted EBITDA attributable to Oasis	265,232	179,396	729,910	471,335
Cash Interest	(39,426)	(36,206)	(117,113)	(106,767)
Capital expenditures[2]	(372,343)	(240,373)	(1,898,105)	(523,143)
Capitalized interest	4,531	3,137	13,209	8,773
Free Cash Flow	$(142,006)	$(94,046)	$(1,272,099)	$(149,802)

(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 (including acquisitions) reflected in the table above differ from the amounts shown in the statements of cash flows in our condensed consolidated financial statements because amounts reflected in this table 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. Acquisitions totaled $55.6 million and $1.1 million for the three months ended September 30, 2018 and 2017, respectively, and $950.1 million and

$5.9 million for the nine months ended September 30, 2018 and 2017, respectively.

Table of Contents

The following tables present reconciliations of the GAAP financial measure of income (loss) before income taxes including non-controlling interests 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,	
	2018	2017	2018	2017
	(In thousands)			
Income (loss) before income taxes including non-controlling interests	$59,375	$(88,835)	$(423,470)	$(71,999)
Gain on sale of properties	(46,459)	—	(48,413)	—
Loss on extinguishment of debt	47	—	13,698	—
Net (gain) loss on derivative instruments	48,544	54,310	239,945	(52,297)
Derivative settlements[1]	(65,190)	8,095	(162,013)	(804)
Interest expense, net of capitalized interest	39,398	37,369	117,009	110,528
Depreciation, depletion and amortization	158,630	129,626	453,083	376,818
Impairment	—	139	384,228	6,021
Exploration expenses	22,315	854	23,701	4,010
Equity-based compensation expenses	7,102	6,344	20,565	19,741
Other non-cash adjustments	574	(208)	557	491
Adjusted EBITDA	$224,336	$147,694	$618,890	$392,509

(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.

Midstream Services

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Income before income taxes including non-controlling interests	$30,959	$25,179	$100,754	$69,046
Loss on sale of properties	9,590	—	9,590	—
Interest expense, net of capitalized interest	162	20	607	20
Depreciation, depletion and amortization	7,373	4,163	20,902	11,375
Equity-based compensation expenses	442	392	1,222	1,104
Adjusted EBITDA	$48,526	$29,754	$133,075	$81,545

Well Services

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands)			
Income before income taxes including non-controlling interests	$9,158	$10,832	$25,316	$9,195
Depreciation, depletion and amortization	3,940	3,196	11,560	9,417
Equity-based compensation expenses	354	281	1,149	1,015
Adjusted EBITDA	$13,452	$14,309	$38,025	$19,627

Table of Contents

Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share

We define Adjusted Net Income (Loss) Attributable to Oasis as net income (loss) after adjusting for (1) the impact of certain non-cash items, including non-cash changes in the fair value of derivative instruments, impairment and other similar non-cash charges, or non-recurring items, (2) the impact of net income attributable to non-controlling interests and (3) the non-cash and non-recurring items' impact on taxes based on our effective tax rate applicable to those adjusting items, excluding net income attributable to non-controlling interests, in the same period. Adjusted Net Income (Loss) Attributable to Oasis is not a measure of net income (loss) as determined by GAAP. We define Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share as Adjusted Net Income (Loss) Attributable to Oasis divided by diluted weighted average shares outstanding. Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share is not a measure of diluted earnings (loss) as determined by GAAP. Management believes that the presentation of Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share provides useful additional information to investors and analysts for evaluating our operational trends and performance in comparison to our peers. This measure is more comparable to earnings estimates provided by securities analysts, and charges or amounts excluded cannot be reasonably estimated and are excluded from guidance provided by the Company.

The following table presents reconciliations of the GAAP financial measure of net income (loss) attributable to Oasis to the non-GAAP financial measure of Adjusted Net Income (Loss) Attributable to Oasis and the GAAP financial measure of diluted earnings (loss) attributable to Oasis per share to the non-GAAP financial measure of Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	(In thousands, except per share data)			
Net income (loss) attributable to Oasis	$62,341	$(41,214)	$(257,273)	$(821)
Gain on sale of properties	(36,869)	—	(38,823)	—
Loss on extinguishment of debt	47	—	13,698	—
Net (gain) loss on derivative instruments	48,544	54,310	239,945	(52,297)
Derivative settlements(1)	(65,190)	8,095	(162,013)	(804)
Impairment	—	139	384,228	6,021
Amortization of deferred financing costs	1,814	1,728	5,512	5,127
Amortization of debt discount	2,852	2,591	8,201	7,426
Other non-cash adjustments	574	(208)	557	491
Tax impact(2)	11,449	(24,941)	(107,140)	12,735
Adjusted Net Income (Loss) Attributable to Oasis	$25,562	$500	$86,892	$(22,122)
Diluted earnings (loss) attributable to Oasis per share	$0.20	$(0.18)	$(0.84)	$0.00
Gain on sale of properties	(0.12)	—	(0.13)	—
Loss on extinguishment of debt	—	—	0.04	—
Net (gain) loss on derivative instruments	0.15	0.23	0.78	(0.22)
Derivative settlements(1)	(0.21)	0.03	(0.52)	—
Impairment	—	—	1.24	0.03
Amortization of deferred financing costs	0.01	0.01	0.02	0.02
Amortization of debt discount	0.01	0.01	0.03	0.03
Other non-cash adjustments	—	—	—	—
Tax impact(2)	0.04	(0.10)	(0.34)	0.05
Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share	$0.08	$0.00	$0.28	$(0.09)

Diluted weighted average shares outstanding(3)	316,387	234,041	308,985	233,248
Effective tax rate applicable to adjustment items	23.7 %	37.4 %	23.7 %	37.4 %

53

(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) The tax impact is computed utilizing our effective tax rate applicable to the adjustments for certain non-cash and non-recurring items.

(3) We included 3,220,000 and 3,452,000 of unvested stock awards for the three and nine months ended September 30, 2018, respectively, and 652,000 of unvested stock awards for the three months ended September 30, 2017 in computing Adjusted Diluted Income Attributable to Oasis Per Share due to the dilutive effect under the treasury stock method. No unvested stock awards were included in computing Adjusted Diluted Loss Attributable to Oasis Per Share for the nine months ended September 30, 2017 because the effect was anti-dilutive due to Adjusted Net Loss Attributable to Oasis.

Fair Value of Financial Instruments

See Note 6 – Fair Value Measurements to our unaudited condensed consolidated financial statements for a discussion of our money market funds and derivative instruments and their related fair value measurements. See also Item 3. “Quantitative and Qualitative Disclosures about Market Risk” below.

Critical Accounting Policies and Estimates

There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2017 Annual Report. See Note 2 – Summary of Significant Accounting Policies to our unaudited condensed consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Item 3. — Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in prices for oil, natural gas and natural gas liquids, and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading. The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our 2017 Annual Report, as well as with the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

We are exposed to a variety of market risks, including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management, including the use of derivative instruments.

Commodity price exposure risk. We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative instruments in the past and expect to enter into derivative instruments in the future to cover a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil and natural gas prices. Our crude oil contracts will settle monthly based on the average NYMEX West Texas Intermediate crude oil index price (“NYMEX WTI”), the average Intercontinental Exchange, Inc. Brent crude oil index price (“ICE Brent”) and the average Argus WTI Midland crude oil index price (“Midland”). The Company’s natural gas contracts will settle monthly based on the average NYMEX Henry Hub natural gas index price (“NYMEX HH”) and the average Inside FERC Northern Natural Gas Ventura natural gas index price (“IF NNG Ventura”).

As of September 30, 2018, we utilized fixed price swaps, basis swaps and two-way and three-way costless collars to reduce the price volatility associated with certain of our oil and natural gas. Our fixed price swaps are comprised of a sold call and a purchased put established at the same price (both ceiling and floor), which we will receive for the volumes under contract. A basis swap transaction has an established fixed basis differential corresponding to two floating index prices. Depending on the difference of the two floating index prices in relation to the fixed basis differential, we either receive an amount from its counterparty, or pay an amount to its counterparty, equal to the difference multiplied by the hedged contract volume. 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) we 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) we will receive for the volumes under contract.

We recognize all derivative instruments at fair value. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet. Derivative assets and liabilities arising from our derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement.

The following is a summary of our derivative contracts as of September 30, 2018:

Commodity	Settlement Period	Derivative Instrument	Index	Volumes		Weighted Average Prices Fixed Price Swaps	Basis Swaps	Sub-Floor	Floor	Ceiling	Fair Valu Asset (Liability)
											(In thousa
Crude oil	2018	Fixed price swaps	NYMEX WTI	3,761,000	Bbl	$52.95					$(71,621
Crude oil	2018	Basis swaps	NYMEX WTI-ICE BRENT	152,000	Bbl		$(9.84)				81
Crude oil	2018	Two-way collar	NYMEX WTI	517,000	Bbl				$58.74	$63.94	(5,171
Crude oil	2019	Fixed price swaps	NYMEX WTI	5,613,000	Bbl	$53.33					(99,347
Crude oil	2019	Basis swaps	NYMEX WTI-ICE BRENT	424,000	Bbl		$(9.68)				408
Crude oil	2019	Two-way collar	NYMEX WTI	3,223,000	Bbl				$57.99	$75.46	(7,580
Crude oil	2019	Three-way collar	NYMEX WTI	3,368,000	Bbl			$40.54	$51.03	$68.68	(21,771
Crude oil	2020	Fixed price swaps	NYMEX WTI	403,000	Bbl	$53.47					(5,911
Crude oil	2020	Two-way collar	NYMEX WTI	279,000	Bbl				$57.78	$76.13	(273
Crude oil	2020	Three-way collar	NYMEX WTI	279,000	Bbl			$40.00	$50.56	$67.80	(1,778
Natural gas	2018	Fixed price swaps	NYMEX HH	3,496,000	MMbtu	$3.01					(104
Natural gas	2018	Basis swaps	IF NNG VENTURA-NYMEX HH	1,225,000	MMbtu		$(0.05)				(64
Natural gas	2019	Fixed price swaps	NYMEX HH	1,896,000	MMbtu	$2.95					16
Natural gas	2019	Basis swaps	IF NNG VENTURA-NYMEX HH	2,715,000	MMbtu		$(0.05)				(31
											$(213,14

A 10% increase in crude oil prices would decrease the fair value of our derivative position by approximately $100.8 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $92.9 million.

Interest rate risk. We had (i) $71.8 million of senior unsecured notes at a fixed cash interest rate of 6.50% per annum, (ii) $1,267.6 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum, (iii) $300.0 million of senior unsecured convertible notes at a fixed cash interest rate of 2.625% per annum and (iv) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.25% per annum outstanding at September 30, 2018.

At September 30, 2018, we had $522.0 million of borrowings and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, which were subject to varying rates of interest based on (i) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (ii) whether the loan is a LIBOR loan or a domestic bank prime interest rate loan (defined in each of the Revolving Credit Facilities as an Alternate Based Rate or "ABR" loan). At September 30, 2018, the outstanding borrowings under the Oasis Credit Facility bore interest at LIBOR plus a 1.75% margin.

At September 30, 2018, we had $166.0 million of borrowings issued under the OMP Credit Facility, which were subject to a per annum interest rate equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the OMP Credit Facility) or (ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the OMP Credit Facility). The applicable margin for borrowings under the OMP Credit Facility varies from (a) in the case of Eurodollar Loans, 1.75% to 2.75%, and (b) in the case of ABR Loans or swingline loans, 0.75% to 1.75%. The unused portion of the OMP Credit Facility is subject to a commitment fee ranging from 0.375% to 0.500%. At September 30, 2018, the outstanding borrowings under the OMP Credit Facility bore interest at LIBOR plus a 1.75% margin.

We do not currently, but may in the future, utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to debt issued under the Oasis Credit Facility or the OMP Credit Facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells. For the three and nine months ended September 30, 2018, we recorded $0.1 million in bad debt expense as a result of our assessment that it is probable certain receivables may not be collected. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us, or their insolvency or liquidation, may adversely affect our financial results.

While we do not require all of our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer's parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. Several of our significant customers for oil and natural gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. However, in order to mitigate the risk of nonperformance, we only enter into derivative contracts with counterparties that are high credit-quality financial institutions, most of which are Lenders under the Oasis Credit Facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the volumes placed under individual contracts. We are likely to enter into future derivative instruments with these or other Lenders under the Oasis Credit Facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative liability position of $213.1 million at September 30, 2018.

As permitted under our investments policy, we may purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. This risk is managed by our investment policy including minimum credit ratings thresholds and maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers failing to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If an issuer fails to repay us at maturity from commercial paper proceeds, it could take a significant amount of time to recover a portion of or all of the assets originally invested. Our commercial paper balance was $36,000 at September 30, 2018.

Item 4. — Controls and Procedures

Evaluation of disclosure controls and procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO"), our principal executive officer, and our Chief Financial Officer ("CFO"), our principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO and CFO as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, our

CEO and CFO have concluded that our disclosure controls and procedures were effective at September 30, 2018.
Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended September 30, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. — Legal Proceedings

Mirada litigation. On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, "Mirada") filed a lawsuit against Oasis, OPNA and Oasis Midstream Services LLC, seeking monetary damages in excess of $100 million, declaratory relief, attorneys' fees and costs (Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). Mirada asserts that it is a working interest owner in certain acreage owned and operated by the Company in Wild Basin. Specifically, Mirada asserts that the Company has breached certain agreements by: (1) failing to allow Mirada to participate in the Company's midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada's consent prior to drilling more than one well at a time in Wild Basin; and (4) overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that the Company be removed as operator in Wild Basin at Mirada's election and that Mirada be allowed to elect a new operator; certain agreements apply to the Company and Mirada and Wild Basin with respect to this dispute; the Company be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and the Company not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada's consent. Mirada also seeks a declaratory judgment with respect to the Company's current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in the Company's Wild Basin midstream operations, consisting of produced water disposal, crude oil gathering and gas gathering and processing; that, upon Mirada's election to participate, Mirada is obligated to pay its proportionate costs of the Company's midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the "Contract Area." On June 30, 2017, Mirada amended its original petition to add a claim that the Company has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleged new legal theories for being entitled to enforce the underlying contracts and added Bighorn DevCo LLC, Bobcat DevCo LLC and Beartooth DevCo LLC as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

On March 2, 2018, Mirada filed a fourth amended petition that described Mirada's alleged ownership and assignment of interests in assets purportedly governed by agreements at issue in the lawsuit. On August 31, 2018, Mirada filed a fifth amended petition that added Oasis Midstream Partners, LP as a defendant, asserting that it was created in bad faith in an effort to avoid contractual obligations owed to Mirada.

The Company believes that Mirada's claims are without merit, that the Company has complied with its obligations under the applicable agreements and that some of Mirada's claims are grounded in agreements that do not apply to the Company. The Company filed answers denying all of Mirada's claims and intends and continues to vigorously defend against Mirada's claims. OMP has not yet filed an answer because it has not yet been served with process. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. Trial is currently scheduled for May 2019. However, the Company cannot predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Company's interests, or if the Company were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Company's business, financial condition, results of operations or cash flows. Such an adverse determination could materially impact the Company's ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in the Company's midstream operations could materially reduce the interests of the Company in their current assets and future midstream opportunities and related revenues in Wild Basin. In addition, the Company has agreed to indemnify OMP for any losses resulting from this litigation under the omnibus agreement it entered into with OMP at the time of OMP's initial public offering.

Item 1A. — Risk Factors

Our business faces many risks. Any of the risks discussed elsewhere in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

Table of Contents

For a discussion of our potential risks and uncertainties, see the information in Item 1A. "Risk Factors" in our 2017 Annual Report. Other than as described below, there have been no material changes in our risk factors from those described in our 2017 Annual Report and subsequent SEC filings.

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

Unregistered sales of equity securities. There were no sales of unregistered equity securities during the period covered by this report.

Issuer purchases of equity securities. The following table contains information about our acquisition of equity securities during the three months ended September 30, 2018:

Period	Total Number of Shares Exchanged[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
July 1 - July 31, 2018	1,242	$ 12.82	—	—
August 1 - August 31, 2018	59,773	11.67	—	—
September 1 - September 30, 2018	2,146	13.46	—	—
Total	63,161	$ 11.75	—	—

(1) Represents shares that employees surrendered back to us to pay tax withholdings upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of our common stock.

Item 6. — Exhibits

Exhibit No.	Description of Exhibit
10.1	Third Amended and Restated Credit Agreement, dated as of October 16, 2018, by and among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties thereto, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 19, 2018 and incorporated herein by reference).
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.

101.LAB(a) XBRL Labels Linkbase Document.

101.PRE(a) XBRL Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith.

Table of Contents

SIGNATURES

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

OASIS PETROLEUM INC.

Date:	November 6, 2018	By:	/s/ Thomas B. Nusz
			Thomas B. Nusz Chairman and Chief Executive Officer (Principal Executive Officer)

By:	/s/ Michael H. Lou
	Michael H. Lou Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)