Oasis Petroleum Inc.
Form 10-Q
November 05, 2015

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, 2015

or

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

For the transition period from to

Commission file number: 1-34776

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

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

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

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

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

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

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

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

Number of shares of the registrant's common stock outstanding at October 30, 2015: 139,117,892 shares.

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

	September 30, 2015	December 31, 2014
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$12,265	$45,811
Accounts receivable — oil and gas revenues	101,977	130,934
Accounts receivable — joint interest partners	96,205	175,537
Inventory	12,929	21,354
Prepaid expenses	8,517	14,273
Derivative instruments	130,747	302,159
Other current assets	1,010	6,539
Total current assets	363,650	696,607
Property, plant and equipment		
Oil and gas properties (successful efforts method)	6,337,945	5,966,140
Other property and equipment	436,052	313,439
Less: accumulated depreciation, depletion, amortization and impairment	(1,466,422)	(1,092,793)
Total property, plant and equipment, net	5,307,575	5,186,786
Derivative instruments	4,699	13,348
Deferred financing costs and other assets	49,184	41,671
Total assets	$5,725,108	$5,938,412
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$19,505	$20,958
Revenues and production taxes payable	152,585	209,890
Accrued liabilities	177,134	410,379
Accrued interest payable	24,650	49,786
Deferred income taxes	35,027	97,499
Advances from joint interest partners	5,377	6,616
Other current liabilities	1,655	—
Total current liabilities	415,933	795,128
Long-term debt	2,380,000	2,700,000
Deferred income taxes	571,412	526,770
Asset retirement obligations	44,975	42,097
Derivative instruments	90	—
Other liabilities	3,216	2,116
Total liabilities	3,415,626	4,066,111
Commitments and contingencies (Note 14)		
Stockholders' equity		
Common stock, $0.01 par value: 300,000,000 shares authorized; 139,603,486 shares issued and 139,111,585 shares outstanding at September 30, 2015 and 101,627,296 shares issued and 101,341,619 shares outstanding at December 31, 2014	1,376	1,001
	(13,442)	(10,671)

Treasury stock, at cost: 491,901 and 285,677 shares at September 30, 2015 and December 31, 2014, respectively		
Additional paid-in capital	1,490,995	1,007,202
Retained earnings	830,553	874,769
Total stockholders' equity	2,309,482	1,872,301
Total liabilities and stockholders' equity	$5,725,108	$5,938,412

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$175,270	$344,706	$563,239	$1,030,735
Well services and midstream revenues	21,965	23,953	44,429	59,821
Total revenues	197,235	368,659	607,668	1,090,556
Operating expenses				
Lease operating expenses	35,670	44,361	112,556	124,903
Well services and midstream operating expenses	10,023	14,922	19,370	34,611
Marketing, transportation and gathering expenses	8,465	7,306	23,313	19,606
Production taxes	16,676	34,584	53,915	100,880
Depreciation, depletion and amortization	123,734	106,972	361,430	295,520
Exploration expenses	327	1,100	2,252	1,955
Rig termination	—	—	3,895	—
Impairment of oil and gas properties	80	1,439	24,917	2,243
General and administrative expenses	22,358	23,915	67,190	68,186
Total operating expenses	217,333	234,599	668,838	647,904
Gain on sale of properties	172	43	172	187,076
Operating income (loss)	(19,926)	134,103	(60,998)	629,728
Other income (expense)				
Net gain on derivative instruments	103,637	103,426	111,285	20,253
Interest expense, net of capitalized interest	(36,513)	(39,420)	(112,702)	(118,568)
Other income (expense)	249	(38)	370	250
Total other income (expense)	67,373	63,968	(1,047)	(98,065)
Income (loss) before income taxes	47,447	198,071	(62,045)	531,663
Income tax benefit (expense)	(20,392)	(76,484)	17,829	(201,290)
Net income (loss)	$27,055	$121,587	$(44,216)	$330,373
Earnings (loss) per share:				
Basic (Note 12)	$0.20	$1.22	$(0.35)	$3.32
Diluted (Note 12)	0.20	1.21	(0.35)	3.29
Weighted average shares outstanding:				
Basic (Note 12)	137,014	99,715	127,827	99,647
Diluted (Note 12)	137,014	100,306	127,827	100,356

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

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

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount			
	(In thousands)						
Balance as of December 31, 2014	101,342	$1,001	286	$(10,671)	$1,007,202	$874,769	$1,872,301
Issuance of common stock	36,800	368	—	—	462,465	—	462,833
Stock-based compensation	1,176	—	—	—	21,335	—	21,335
Vesting of restricted shares	—	7	—	—	(7)	—	—
Treasury stock – tax withholdings	(206)	—	206	(2,771)	—	—	(2,771)
Net loss	—	—	—	—	—	(44,216)	(44,216)
Balance as of September 30, 2015	139,112	$1,376	492	$(13,442)	$1,490,995	$830,553	$2,309,482

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

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

	Nine Months Ended September 30, 2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(44,216)	$330,373
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	361,430	295,520
Gain on sale of properties	(172)	(187,076)
Impairment of oil and gas properties	24,917	2,243
Deferred income taxes	(17,829)	197,548
Derivative instruments	(111,285)	(20,253)
Stock-based compensation expenses	19,629	15,755
Deferred financing costs amortization and other	7,468	5,209
Working capital and other changes:		
Change in accounts receivable	108,309	(62,581)
Change in inventory	8,425	(4,089)
Change in prepaid expenses	638	(3,179)
Change in other current assets	5,529	(1,581)
Change in other assets	—	(3,069)
Change in accounts payable and accrued liabilities	(84,133)	108,788
Change in other current liabilities	1,655	—
Change in other liabilities	(28)	(116)
Net cash provided by operating activities	280,337	673,492
Cash flows from investing activities:		
Capital expenditures	(740,633)	(998,889)
Proceeds from sale of properties	78	324,938
Costs related to sale of properties	—	(2,337)
Derivative settlements	291,436	(24,773)
Advances from joint interest partners	(1,239)	(6,053)
Net cash used in investing activities	(450,358)	(707,114)
Cash flows from financing activities:		
Proceeds from sale of common stock	462,833	—
Proceeds from revolving credit facility	618,000	370,000
Principal payments on revolving credit facility	(938,000)	(355,570)
Deferred financing costs	(3,587)	(99)
Purchases of treasury stock	(2,771)	(5,240)
Other	—	(176)
Net cash provided by financing activities	136,475	8,915
Decrease in cash and cash equivalents	(33,546)	(24,707)
Cash and cash equivalents:		
Beginning of period	45,811	91,901
End of period	$12,265	$67,194
Supplemental non-cash transactions:		
Change in accrued capital expenditures	$(233,913)	$99,103
Change in asset retirement obligations	3,405	5,134

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

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OASIS PETROLEUM INC.
Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Organization and Operations of the Company

Organization

Oasis Petroleum Inc. (together with its subsidiaries, “Oasis” or the “Company”) was formed on February 25, 2010, pursuant to the laws of the State of Delaware, to become a holding company for Oasis Petroleum LLC (“OP LLC”), the Company’s predecessor, which was formed as a Delaware limited liability company on February 26, 2007. In connection with its initial public offering in June 2010 and related corporate reorganization, the Company acquired all of the outstanding membership interests in OP LLC in exchange for shares of the Company’s common stock. Oasis Petroleum North America LLC (“OPNA”), a Delaware limited liability company formed in 2007, conducts the Company’s domestic oil and natural gas exploration and production activities. In 2011, the Company formed Oasis Well Services LLC (“OWS”), a Delaware limited liability company, to provide well services to OPNA, and Oasis Petroleum Marketing LLC (“OPM”), a Delaware limited liability company, to provide marketing services to OPNA. In 2013, the Company formed Oasis Midstream Services LLC (“OMS”), a Delaware limited liability company, to provide midstream services to OPNA.

Nature of Business

The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the Williston Basin. The Company’s proved and unproved oil and natural gas properties are located in the North Dakota and Montana areas of the Williston Basin and are owned by OPNA. The Company also operates an oil and gas marketing business (OPM), a well services business (OWS) and a midstream services business (OMS), all of which are complementary to its primary development and production activities. Both OWS and OMS are separate reportable business segments, while OPM is included in the Company’s exploration and production segment.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. The accompanying condensed consolidated financial statements of the Company have not been audited by the Company’s independent registered public accounting firm, except that the Condensed Consolidated Balance Sheet at December 31, 2014 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 presentation, 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, 2014 (“2014 Annual Report”).

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. Crude oil prices declined significantly in the latter part of 2014 and have remained low while experiencing high volatility in 2015. As a result of lower oil prices, the Company significantly decreased its 2015 capital expenditures as compared to 2014 and is currently concentrating its drilling activities in certain areas that are the most economic in the Williston Basin. An extended period of low prices for oil could have a material adverse effect on the Company's financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.

Significant Accounting Policies

There have been no material changes to the Company's critical accounting policies and estimates from those disclosed in the 2014 Annual Report.

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Recent Accounting Pronouncements

Revenue recognition. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, Deferral of the Effective Date ("ASU 2015-14"). ASU 2015-14 defers the effective date of the new revenue standard by one year, making it effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

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

Extraordinary items. In January 2015, the FASB issued Accounting Standards Update No. 2015-01, Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items ("ASU 2015-01"). ASU 2015-01 removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net-of-tax presentation will no longer be allowed. ASU 2015-01 is effective for fiscal years beginning after December 15, 2015, including interim periods within those years. The Company does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or results of operations.

Debt issuance costs. In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of debt discount, but it does not affect the recognition or measurement of debt issuance costs. ASU 2015-03 is effective for fiscal years beginning after December 15, 2015, including interim periods within those years, and should be applied on a retrospective basis for all prior periods presented. The Company expects that the adoption of this guidance will only impact the presentation of its balance sheet. As of September 30, 2015 and December 31, 2014, the Company had capitalized, unamortized debt issuance costs associated with debt liabilities other than line-of-credit arrangements of $25.9 million and $29.3 million, respectively, included in deferred financing costs and other assets on its Condensed Consolidated Balance Sheet. In August 2015, the FASB issued Accounting Standards Update No. 2015-15, Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements ("ASU 2015-15"), which confirms that line-of-credit arrangements are not in the scope of ASU 2015-03. ASU 2015-15 states that, for debt issuance costs related to line-of-credit arrangements, the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are outstanding borrrowings under the line-of-credit arrangement.

Inventory. In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Simplifying the Measurement of Inventory ("ASU 2015-11"). ASU 2015-11 changes the inventory measurement principle from lower of cost or market to lower of cost and net realizable value for entities using the first-in, first out (FIFO) or average cost methods. ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Business combinations. In September 2015, the FASB issued Accounting Standards Update No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments ("ASU 2015-16"), which eliminates the requirement for an acquirer in a business combination to restate prior period financial statements for measurement period adjustments. ASU 2015-16 requires that the cumulative impact of measurement period adjustments on current and prior periods be recognized in the reporting period in which the adjustment amount is determined. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

3. Inventory

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 includes oil in tank and linefill. Inventory is stated at the lower of cost or market value with cost determined on an average cost method. Inventory consists of the following:

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	September 30, 2015	December 31, 2014
	(In thousands)	
Equipment and materials	$5,569	$14,225
Crude oil inventory	7,360	7,129
Total inventory	$12,929	$21,354

4. Property, Plant and Equipment

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

	September 30, 2015	December 31, 2014
	(In thousands)	
Proved oil and gas properties[(1)]	$5,669,125	$5,156,875
Less: Accumulated depreciation, depletion, amortization and impairment	(1,393,283)	(1,043,121)
Proved oil and gas properties, net	4,275,842	4,113,754
Unproved oil and gas properties	668,820	809,265
Total oil and gas properties, net	4,944,662	4,923,019
Other property and equipment	436,052	313,439
Less: Accumulated depreciation	(73,139)	(49,672)
Other property and equipment, net	362,913	263,767
Total property, plant and equipment, net	$5,307,575	$5,186,786

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $38.4 million and $36.9 million at September 30, 2015 and December 31, 2014, respectively.

Impairment. As a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and natural gas properties of $0.1 million and $24.9 million for the three and nine months ended September 30, 2015, respectively, and $1.4 million and $2.2 million for the three and nine months ended September 30, 2014, respectively. The impairment charges for the nine months ended September 30, 2015 included $16.4 million related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. For the three months ended September 30, 2015 and the three and nine months ended September 30, 2014, the Company did not record similar impairment charges based on its ability to actively manage and prioritize its capital expenditures to drill leases and to make payments to extend leases that would have otherwise expired. No impairment charges on proved oil and gas properties were recorded for the three and nine months ended September 30, 2015 or 2014.

Divestiture. On March 5, 2014, the Company completed the sale of certain non-operated properties in and around its Sanish position for cash proceeds of $324.9 million, which included customary post close adjustments. The Company recognized a $187.0 million gain on sale of properties in its Consolidated Statement of Operations for the year ended December 31, 2014.

5. Fair Value Measurements

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

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

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

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

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

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

Financial Assets and Liabilities

As required, 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:

	At fair value as of September 30, 2015			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$742	$—	$—	$742
Commodity derivative instruments (see Note 6)	—	135,446	—	135,446
Total assets	$742	$135,446	$—	$136,188
Liabilities:				
Commodity derivative instruments (see Note 6)	$—	$90	$—	$90
Total liabilities	$—	$90	$—	$90

	At fair value as of December 31, 2014			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$742	$—	$—	$742
Commodity derivative instruments (see Note 6)	—	315,507	—	315,507
Total assets	$742	$315,507	$—	$316,249

The Level 1 instruments presented in the tables above consist of money market funds included in cash and cash equivalents on the Company's Condensed Consolidated Balance Sheet at September 30, 2015 and December 31, 2014. 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 collars and swaps. The fair values of the Company's commodity derivative instruments are based upon a third-party preparer's calculation using mark-to-market valuation reports provided by the Company's counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts, as there is an active market for these contracts. The third-party preparer performs its independent valuation using a moment matching method similar to Turnbull-Wakeman for Asian options. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The Company compares the third-party preparer’s valuation to counterparty valuation statements,

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investigating any significant differences, and analyzes monthly valuation changes in relation to movements in crude oil 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 asset by $0.2 million and $0.6 million at September 30, 2015 and December 31, 2014, respectively.

Fair Value of Other Financial Instruments

The Company’s financial instruments, including certain cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. At September 30, 2015, the Company’s cash equivalents were all Level 1 assets.

The carrying amount of the Company’s long-term debt reported in the Condensed Consolidated Balance Sheet at September 30, 2015 was $2,380.0 million, which includes $2,200.0 million of senior unsecured notes and $180.0 million of borrowings under the revolving credit facility (see Note 7 – Long-Term Debt). The fair value of the Company’s senior unsecured notes, which are publicly traded and therefore categorized as Level 1 liabilities, was $1,771.3 million at September 30, 2015.

Non-Financial Assets and Liabilities

Asset retirement obligations. The carrying amount of ARO in the Company’s Condensed Consolidated Balance Sheet at September 30, 2015 was $45.6 million (see Note 8 – Asset Retirement Obligations). The Company determines its ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding the timing and existence of a liability, as well as what constitutes adequate restoration when considering current regulatory requirements. Inherent in the fair value calculation are numerous assumptions and judgments, including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Impairment. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its proved oil and natural gas properties then compares such undiscounted future cash flows to the carrying amount of the proved oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management’s judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs. No impairment charges on proved oil and natural gas properties were recorded for the three and nine months ended September 30, 2015 or 2014.

6. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of September 30, 2015, the Company utilized two-way costless collar options and swaps to reduce the volatility of oil prices on a significant portion of its future expected oil production. 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 swap is a sold call and a purchased put established at the same price (both ceiling and floor).

All derivative instruments are recorded on the Company’s Condensed Consolidated Balance Sheet as either assets or liabilities measured at fair value (see Note 5 – Fair Value Measurements). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value are recognized in the other income (expense) section of the Company's Condensed Consolidated Statement of Operations as a net gain or loss on derivative instruments. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making a payment to or receiving a payment from the counterparty. These cash settlements represent the cumulative

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gains and losses on the Company's derivative instruments and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled. Cash settlements are reflected as investing activities in the Company's Condensed Consolidated Statement of Cash Flows.

As of September 30, 2015, the Company had the following outstanding commodity derivative instruments, all of which settle monthly based on the average WTI:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices Swap	Floor	Ceiling	Fair Value
		(Barrels)	($/Barrel)			(In thousands)
2015	Two-way collars	455,000		$86.00	$103.42	$18,790
2015	Swaps	2,093,000	$73.35			57,933
2016	Two-way collars	155,000		$86.00	$103.42	6,133
2016	Swaps	5,643,000	$57.75			51,499
2017	Swaps	372,000	$53.84			1,001
						$135,356

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

Commodity	Balance Sheet Location	Fair Value Asset (Liability) September 30, 2015	December 31, 2014
		(In thousands)	
Crude oil	Derivative instruments — current assets	$130,747	$302,159
Crude oil	Derivative instruments — non-current assets	4,699	13,348
Crude oil	Derivative instruments — non-current liabilities	(90)	—
Total derivative instruments		$135,356	$315,507

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

Statement of Operations Location	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
	(In thousands)			
Net gain on derivative instruments	$103,637	$103,426	$111,285	$20,253

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

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

Offsetting of Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
	(In thousands)		
As of September 30, 2015	$153,394	$(17,948)	$ 135,446
As of December 31, 2014	331,121	(15,614)	315,507

Offsetting of Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet
	(In thousands)		
As of September 30, 2015	$18,038	$(17,948)	$ 90
As of December 31, 2014	15,614	(15,614)	—

7. Long-Term Debt

Senior unsecured notes. During 2013, the Company issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the "2022 Notes"), which resulted in aggregate net proceeds to the Company of $983.6 million. The Company used the proceeds from the 2022 Notes to fund the acquisition of oil and gas properties. During 2011 and 2012, the Company issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the "2019 Notes"), $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the "2021 Notes") and $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the "2023 Notes"), which resulted in aggregate net proceeds to the Company of $1,175.8 million. The Company used the proceeds from these notes to fund its exploration, development and acquisition program and for general corporate purposes. Interest on the 2019 Notes, the 2021 Notes, the 2022 Notes and the 2023 Notes (collectively, the "Notes") is payable semi-annually in arrears.

The Notes were issued under indentures containing provisions that are substantially the same, as amended and supplemented by supplemental indentures (collectively, the "Indentures"), among the Company, along with its material subsidiaries (the "Guarantors"), and U.S. Bank National Association, as trustee. The Notes are guaranteed on a senior unsecured basis by the Company's 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, as follows:

- in connection with any sale or other disposition of all or substantially all of the assets of that Guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary (as defined in the Indentures) of the Company;
- in connection with any sale or other disposition of the capital stock of that Guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, such that, immediately after giving effect to such transaction, such Guarantor would no longer constitute a subsidiary of the Company;
- if the Company designates any Restricted Subsidiary that is a Guarantor to be an unrestricted subsidiary in accordance with the Indenture;
- upon legal defeasance or satisfaction and discharge of the Indenture; or
- upon the liquidation or dissolution of a Guarantor, provided no event of default occurs under the Indentures as a result thereof.

Prior to certain dates, the Company has certain options to redeem up to 35% of the Notes at a certain redemption price based on a percentage of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to certain dates, the Company has the option to redeem some or all of the Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The Company estimates that the fair value of these redemption options is immaterial at September 30, 2015 and December 31, 2014.

The Indentures restrict the Company's ability and the ability of certain of its 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 certain exceptions and qualifications. If at any time when the 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 the Company and its subsidiaries will cease to be subject to such covenants.

The Indentures contain customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;

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- default in the payment of principal or premium, if any, on any Note when due;
- failure by the Company to comply with its other obligations under the Indentures, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries in the aggregate principal amount of $10.0 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the Indentures) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;
- failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $10.0 million within 60 days; and
- any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

Senior secured revolving line of credit. On April 5, 2013, the Company, as parent, and OPNA, as borrower, entered into a second amended and restated credit agreement (the “Second Amended Credit Facility”), which had a maturity date of April 5, 2018. The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On April 13, 2015, the Company entered into its third amendment to the Second Amended Credit Facility (the “Third Amendment”), which extended the maturity date of the Second Amended Credit Facility to April 13, 2020, provided that the 2019 Notes are retired or refinanced 90 days prior to their maturity. In connection with the Third Amendment, the lenders under the Second Amended Credit Facility (the “Lenders”) completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2015, resulting in a borrowing base decrease from $2,000.0 million to $1,700.0 million. The Company increased the Lenders’ aggregate elected commitment from $1,500.0 million to $1,525.0 million. The Lenders’ aggregate commitment can be increased to the full $1,700.0 million borrowing base by increasing the commitment of one or more Lenders. The Third Amendment also increased the Lenders in the bank group to 18 financial institutions supporting the Company’s borrowing base facility. The overall senior secured line of credit under the Second Amended Credit Facility is $2,500.0 million as of September 30, 2015.

Borrowings under the Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company’s assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.

Borrowings under the Second Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate (“LIBOR”) loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or “ABR” loan). As of September 30, 2015, any outstanding LIBOR and ABR loans bore their respective interest rates plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for LIBOR Loans		Applicable Margin for ABR Loans	
Less than .25 to 1	1.50	%	0.00	%
Greater than or equal to .25 to 1 but less than .50 to 1	1.75	%	0.25	%
Greater than or equal to .50 to 1 but less than .75 to 1	2.00	%	0.50	%
Greater than or equal to .75 to 1 but less than .90 to 1	2.25	%	0.75	%
Greater than or equal to .90 to 1	2.50	%	1.00	%

An ABR loan may be repaid at any time before the scheduled maturity of the Second Amended Credit Facility upon the Company providing advance notification to the Lenders. Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for

LIBOR loans that have loan terms greater than three months in duration. At the end of a LIBOR loan term, the Second Amended Credit Facility allows the Company to elect to repay the borrowing, continue a LIBOR loan with the same or a differing loan term or convert the borrowing to an ABR loan.

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On a quarterly basis, the Company pays a 0.375% (as of September 30, 2015) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

As of September 30, 2015, the Second Amended Credit Facility contained covenants that included, 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 the assets of the Company and its 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 the Company maintain a ratio of consolidated EBITDAX (as defined in the Second Amended Credit Facility) to consolidated Interest Expense (as defined in the Second Amended Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter; and
- a requirement that the Company maintain a Current Ratio (as defined in the Second Amended Credit Facility) of consolidated current assets (including unused borrowing base capacity and with exclusions as described in the Second Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Second Amended Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Second Amended 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 Second Amended Credit Facility to be immediately due and payable.

As of September 30, 2015, the Company had $180.0 million of LIBOR loans and $5.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused borrowing base committed capacity of $1,339.8 million. As of September 30, 2015 and December 31, 2014, the weighted average interest rate on borrowings outstanding under the Second Amended Credit Facility was 1.7% and 1.9%, respectively. The Company was in compliance with the financial covenants of the Second Amended Credit Facility as of September 30, 2015.

Deferred financing costs. As of September 30, 2015, the Company had $33.6 million of deferred financing costs related to the Notes and the Second Amended Credit Facility. The deferred financing costs are included in deferred financing costs and other assets on the Company’s Condensed Consolidated Balance Sheet at September 30, 2015 and are being amortized over the respective terms of the Notes and the Second Amended Credit Facility. Amortization of deferred financing costs recorded for the three and nine months ended September 30, 2015 was $1.6 million and $5.5 million, respectively, and $1.6 million and $4.8 million for the three and nine months ended September 30, 2014, respectively. These costs are included in interest expense on the Company’s Condensed Consolidated Statement of Operations.

8. Asset Retirement Obligations

The following table reflects the changes in the Company’s ARO during the nine months ended September 30, 2015:

	(In thousands)
Balance at December 31, 2014	$42,549
Liabilities incurred during period	1,233
Liabilities settled during period	(112)
Accretion expense during period[1]	1,654
Revisions to estimates	241
Balance at September 30, 2015	$45,565

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

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At September 30, 2015, the current portion of the total ARO balance was approximately $0.6 million and is included in accrued liabilities on the Company's Condensed Consolidated Balance Sheet.

9. Income Taxes

The Company's effective tax rate for the three and nine months ended September 30, 2015 was 43.0% and 28.7%, respectively. The Company's effective tax rate for the three and nine months ended September 30, 2014 was 38.6% and 37.9%, respectively. While the 2014 rates were consistent with the statutory tax rate applicable to the U.S. and the blended state rate for the states in which the Company conducts business, the effective tax rate was higher for the three months ended September 30, 2015 due to lower pre-tax income and the impact of permanent differences, while the effective tax rate was lower for the nine months ended September 30, 2015 due to the Company's pre-tax loss and the impact of permanent differences. The permanent differences were primarily between compensation amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vestings during the three and nine months ended September 30, 2015 at stock prices lower than the grant date values. The impact of these permanent differences was partially offset by a reduction in the North Dakota statutory tax rate in the second quarter of 2015.

The Company had deferred tax assets for its federal and state tax loss carryforwards at September 30, 2015 recorded in deferred income taxes. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2015, management determined that a valuation allowance was not required for the tax loss carryforwards as they are expected to be fully utilized before expiration. As of September 30, 2015, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

10. Stock-Based Compensation

Restricted stock awards. The Company has granted restricted stock awards to employees and directors under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the closing sales price of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. For the nine months ended September 30, 2015, the Company assumed annual forfeiture rates by employee group ranging from 0% to 16.9% based on the Company's forfeiture history for this type of award.

During the nine months ended September 30, 2015, employees and non-employee directors of the Company were granted restricted stock awards equal to 1,234,320 shares of common stock with a $13.08 weighted average grant date per share value. Stock-based compensation expense recorded for restricted stock awards for the three and nine months ended September 30, 2015 was $5.0 million and $16.8 million, respectively, and $5.2 million and $13.4 million for the three and nine months ended September 30, 2014, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

Performance share units. The Company has granted performance share units ("PSUs") to officers of the Company under its Amended and Restated 2010 Long Term Incentive Plan. The PSUs are awards of restricted stock units, and each PSU that is earned represents the right to receive one share of the Company's common stock. For the nine months ended September 30, 2015, the Company assumed annual forfeiture rates by employee group ranging from 2.4% to 4.9% based on the Company's forfeiture history for the officer employee groups receiving PSUs.

During the nine months ended September 30, 2015, officers of the Company were granted 425,590 PSUs with an $11.20 weighted average grant date per share value. Stock-based compensation expense recorded for PSUs for the three and nine months ended September 30, 2015 was $1.0 million and $2.9 million, respectively, and $0.8 million and $2.3 million for the three and nine months ended September 30, 2014, respectively, and is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

Each grant of PSUs is subject to a designated three-year initial performance period. 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 period. 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. If less than 200% of the initial PSUs granted are earned at the end of the initial three-year performance period, then the performance period will be extended an

additional year to give the award recipients the opportunity to earn up to an aggregate of 200% of the initial PSUs granted.
The Company accounted for these PSUs as equity awards pursuant to the FASB’s authoritative guidance for share-based payments. The aggregate grant date fair value of the market-based awards was determined using a Monte Carlo simulation

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model, which results in an expected percentage of PSUs earned. The fair value of these PSUs is recognized on a straight-line basis over the performance period. As it is probable that a portion of the awards will be earned during the extended performance period, the grant date fair value will be amortized over four years. However, if 200% of the initial PSUs granted are earned at the end of the initial performance period, then the remaining compensation expense will be accelerated in order to be fully recognized over three years. 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 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, risk-free interest rate, volatility and correlation coefficients. The risk-free interest rate is the U.S. Treasury bond rate on the date of grant that corresponds to the extended performance period. The initial value is the average of the volume weighted average prices for the 30 trading days prior to the start of the performance cycle for the Company and each of its peers. Volatility is the standard deviation of the average percentage change in stock price over a historical period for the Company and each of its peers. The correlation coefficients are measures of the strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the PSUs granted during the nine months ended September 30, 2015:

Forecast period (years)	4.00	
Risk-free interest rate	0.99	%
Oasis stock price volatility	50.11	%

For the PSUs granted during the nine months ended September 30, 2015, the Monte Carlo simulation model resulted in 86% of PSUs expected to be earned over the extended performance period.

11. Common Stock

On March 9, 2015, the Company completed a public offering of 36,800,000 shares of its common stock (including 4,800,000 shares issued pursuant to the underwriters' option to purchase additional common stock) at an offering price of $12.80 per share. Net proceeds from the offering were $463.1 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which $0.4 million is included in common stock and $462.7 million is included in additional paid-in capital on the Company's Condensed Consolidated Balance Sheet. The Company used the net proceeds to repay outstanding indebtedness under its Second Amended Credit Facility and for general corporate purposes. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on July 15, 2014.

12. Earnings (Loss) Per Share

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

The following is a calculation of the basic and diluted weighted-average shares outstanding for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Basic weighted average common shares outstanding	137,014	99,715	127,827	99,647
Dilution effect of stock awards at end of period[1]	—	591	—	709
Diluted weighted average common shares outstanding	137,014	100,306	127,827	100,356
Anti-dilutive stock-based compensation awards	2,787	1,067	2,939	927

(1)

No unvested stock awards were included in computing earnings (loss) per share for the three and nine months ended September 30, 2015 because the effect was anti-dilutive.

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13. Business Segment Information

The Company’s exploration and production segment is engaged in the acquisition and development of oil and natural gas properties and includes the complementary marketing services provided by OPM. Revenues for the exploration and production segment are derived from the sale of oil and natural gas production. In the first quarter of 2012, the Company began its well services business segment (OWS) to perform 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 completion services, well completion product sales and tool rentals. In the first quarter of 2013, the Company formed its midstream services business segment (OMS) to perform salt water gathering and disposal and other midstream services for the Company’s oil and natural gas wells operated by OPNA. Revenues for the midstream segment are primarily derived from salt water transport, salt water disposal and fresh water sales. The revenues and expenses related to work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation, and only the revenues and expenses related to non-affiliated working interest owners are included in the Company’s Condensed Consolidated Statement of Operations. These segments represent the Company’s three current 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. The following table summarizes financial information for the Company’s business segments for the periods presented:

	Exploration and Production	Well Services	Midstream Services	Eliminations	Consolidated
	(In thousands)				
Three months ended September 30, 2015:					
Revenues from non-affiliates	$175,270	$15,381	$6,584	$—	$197,235
Inter-segment revenues	—	33,554	23,228	(56,782)	—
Total revenues	175,270	48,935	29,812	(56,782)	197,235
Operating income (loss)	(38,289)	10,936	18,828	(11,401)	(19,926)
Other income (expense)	67,359	14	—	—	67,373
Income before income taxes	$29,070	$10,950	$18,828	$(11,401)	$47,447
Three months ended September 30, 2014:					
Revenues from non-affiliates	$344,706	$20,925	$3,028	$—	$368,659
Inter-segment revenues	—	66,298	10,596	(76,894)	—
Total revenues	344,706	87,223	13,624	(76,894)	368,659
Operating income	126,184	23,388	5,126	(20,595)	134,103
Other income (expense)	63,968	—	—	—	63,968
Income before income taxes	$190,152	$23,388	$5,126	$(20,595)	$198,071
Nine months ended September 30, 2015:					
Revenues from non-affiliates	$563,239	$27,308	$17,121	$—	$607,668
Inter-segment revenues	—	131,220	58,994	(190,214)	—
Total revenues	563,239	158,528	76,115	(190,214)	607,668
Operating income (loss)	(103,065)	29,554	44,083	(31,570)	(60,998)
Other income (expense)	(1,037)	34	(44)	—	(1,047)
Income (loss) before income taxes	$(104,102)	$29,588	$44,039	$(31,570)	$(62,045)
Nine months ended September 30, 2014:					
Revenues from non-affiliates	$1,030,735	$51,630	$8,191	$—	$1,090,556
Inter-segment revenues	—	146,447	28,264	(174,711)	—

Total revenues	1,030,735	198,077	36,455	(174,711)	1,090,556
Operating income	602,797	53,137	15,854	(42,060)	629,728
Other income (expense)	(98,140)	75	—	—	(98,065)

Income before income taxes	$504,657	$53,212	$15,854	$(42,060)	$531,663
As of September 30, 2015:					
Property, plant and equipment, net	$5,130,061	$66,058	$261,989	$(150,533)	$5,307,575
Total assets	5,541,674	421,642	378,284	(616,492)	5,725,108
As of December 31, 2014:					
Property, plant and equipment, net	$5,074,588	$58,767	$172,394	$(118,963)	$5,186,786
Total assets	5,802,295	281,844	212,685	(358,412)	5,938,412

14. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of September 30, 2015. The commitments under these arrangements are not recorded in the accompanying Condensed Consolidated Balance Sheet. The amounts disclosed represent undiscounted cash flows on a gross basis, and no inflation elements have been applied.

Lease obligations. The Company's total rental commitments under leases for office space and other property and equipment at September 30, 2015 were $28.7 million.

Drilling contracts. As a result of its lowered 2015 capital expenditure program, the Company elected to early terminate certain drilling rig contracts and recorded a rig termination expense of $3.9 million in its Condensed Consolidated Statement of Operations for the nine months ended September 30, 2015. The Company did not elect to early terminate any drilling rig contracts during the nine months ended September 30, 2014.

As of September 30, 2015, the Company had certain drilling rig contracts with initial terms greater than one year. In the event of early termination under these contracts, the Company would be obligated to pay approximately $5.3 million as of September 30, 2015 for the days remaining through the end of the primary terms of the contracts.

Volume commitment agreements. As of September 30, 2015, the Company had certain agreements with an aggregate requirement to deliver a minimum quantity of approximately 29.2 MMBbl and 4.1 Bcf, prior to any applicable volume credits, within specified timeframes, all of which are less than ten years. Future commitments under these agreements were approximately $193.8 million as of September 30, 2015.

Purchase agreements. As of September 30, 2015, the Company had certain agreements for the purchase of fresh water with an aggregate future commitment of approximately $38.6 million.

Cost sharing agreements. As of September 30, 2015, the Company had certain agreements to share the cost to construct and install electrical facilities. The Company's estimated future commitment under these agreements was $2.3 million as of September 30, 2015.

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

On July 6, 2013, a freight train operated by Montreal, Maine and Atlantic Railway ("MMA") carrying crude oil (the "Train") derailed in Lac-Mégantic, Quebec. In March 2014, Oasis Petroleum Inc. and OP LLC were added to a group of over fifty named defendants, including other crude oil producers as well as the Canadian Pacific Railway, MMA and certain of its affiliates, owners and transloaders of the crude oil carried by the Train, several lessors of tank cars, and the Attorney General of Canada, in a motion filed in the Quebec Superior Court to authorize a class-action lawsuit seeking economic, compensatory and punitive damages, as well as costs for claims arising out of the derailment of the Train (Yannick Gagne, etc., et al. v. Rail World, Inc., etc., et al., Case No. 48006000001132) (the "Class-Action"). The motion generally alleges wrongful death and negligence in the failure to provide for the proper and safe transportation of crude oil. The Company believes that all claims against Oasis Petroleum Inc. and OP LLC in connection with the derailment of the Train in Lac-Mégantic, Quebec are without merit.

On August 7, 2013, MMA filed for bankruptcy protection in the Quebec Superior Court and the United States Bankruptcy Court in Bangor, Maine (together, the “Bankruptcy Actions”). The trustees appointed in the Bankruptcy Actions have

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negotiated settlement agreements with the majority of the named defendants in the Class-Action, including Oasis Petroleum Inc. and OP LLC. The Quebec Superior Court and the United States Bankruptcy Court have issued orders approving the settlement agreements which were pending before them, but such orders have not yet become final and are subject to appeal. If the orders become final, pursuant to the settlement agreements, Oasis Petroleum Inc. and OP LLC have agreed to contribute to the compensation fund established for those suffering losses as a result of the Lac-Megantic derailment. The Company has determined that such contributions are fully covered by the Company's insurance policies. Furthermore, the settlement agreements would bar future litigation against Oasis Petroleum Inc. and OP LLC in Canada and the United States arising out of the Lac-Megantic derailment.

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15. Condensed Consolidating Financial Information

The Notes (see Note 7) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company's immaterial wholly-owned subsidiaries do not guarantee the Notes ("Non-Guarantor Subsidiaries").

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

Condensed Consolidating Balance Sheet

	September 30, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
ASSETS				
Cash and cash equivalents	$757	$11,508	$—	$12,265
Accounts receivable	16	198,166	—	198,182
Accounts receivable – affiliates	1,258	221,784	(223,042)	—
Inventory	—	12,929	—	12,929
Prepaid expenses	417	8,100		8,517
Other current assets	—	131,757	—	131,757
Oil and gas properties (successful efforts method)	—	6,337,945	—	6,337,945
Other property and equipment	—	436,052	—	436,052
Accumulated depreciation, depletion, amortization and impairment	—	(1,466,422)	—	(1,466,422)
Investments in and advances to subsidiaries	4,526,226	—	(4,526,226)	—
Other long-term assets	227,143	27,849	(201,109)	53,883
Total assets	$4,755,817	$5,919,668	$(4,950,377)	$5,725,108
LIABILITIES AND EQUITY				
Accounts payable – affiliates	221,784	1,258	(223,042)	—
Other current liabilities	24,551	391,382	—	415,933
Long-term debt	2,200,000	180,000	—	2,380,000
Other long-term liabilities	—	820,802	(201,109)	619,693
Common stock	1,376	—	—	1,376
Other stockholders' equity	2,308,106	4,526,226	(4,526,226)	2,308,106
Total liabilities and stockholders' equity	$4,755,817	$5,919,668	$(4,950,377)	$5,725,108

Condensed Consolidating Balance Sheet

	December 31, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			

ASSETS				
Cash and cash equivalents	$776	$45,035	$—	$45,811
Accounts receivable	—	306,471	—	306,471
Accounts receivable – affiliates	781	91,459	(92,240)	—
Prepaid expenses	297	13,976	—	14,273
Other current assets	—	330,052	—	330,052
Oil and gas properties (successful efforts method)	—	5,966,140	—	5,966,140
Other property and equipment	—	313,439	—	313,439
Accumulated depreciation, depletion, amortization and impairment	—	(1,092,793)	—	(1,092,793)
Investments in and advances to subsidiaries	4,032,494	—	(4,032,494)	—
Other long-term assets	178,752	25,584	(149,317)	55,019
Total assets	$4,213,100	$5,999,363	$(4,274,051)	$5,938,412
LIABILITIES AND EQUITY				
Accounts payable	$—	$20,958	$—	$20,958
Accounts payable – affiliates	91,459	781	(92,240)	—
Other current liabilities	49,340	724,830	—	774,170
Long-term debt	2,200,000	500,000	—	2,700,000
Other long-term liabilities	—	720,300	(149,317)	570,983
Total stockholders' equity	1,872,301	4,032,494	(4,032,494)	1,872,301
Total liabilities and stockholders' equity	$4,213,100	$5,999,363	$(4,274,051)	$5,938,412

Condensed Consolidating Statement of Operations

	Three Months Ended September 30, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Total revenues	$—	$197,235	$—	$197,235
Total operating expenses	(5,903)	(211,430)	—	(217,333)
Gain on sale of properties	—	172	—	172
Operating loss	(5,903)	(14,023)	—	(19,926)
Equity in earnings of subsidiaries	49,899	—	(49,899)	—
Interest expense, net of capitalized interest	(34,020)	(2,493)	—	(36,513)
Other income (expense)	1	103,885	—	103,886
Income before income taxes	9,977	87,369	(49,899)	47,447
Income tax benefit (expense)	17,078	(37,470)	—	(20,392)
Net income	$27,055	$49,899	$(49,899)	$27,055

Condensed Consolidating Statement of Operations

	Three Months Ended September 30, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Total revenues	$—	$368,659	$—	$368,659
General and administrative expenses	(6,373)	(17,542)	—	(23,915)
Other operating expenses	—	(210,684)	—	(210,684)
Gain on sale of properties	—	43	—	43
Operating income (loss)	(6,373)	140,476	—	134,103
Equity in earnings of subsidiaries	148,357	—	(148,357)	—

Interest expense, net of capitalized interest	(36,724)	(2,696)	—	(39,420)
Other income (expense)	—	103,388	—	103,388
Income before income taxes	105,260	241,168	(148,357)	198,071
Income tax benefit (expense)	16,327	(92,811)	—	(76,484)
Net income	$121,587	$148,357	$(148,357)	$121,587

Condensed Consolidating Statement of Operations

	Nine Months Ended September 30, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Total revenues	$—	$607,668	$—	$607,668
General and administrative expenses	(20,847)	(46,343)	—	(67,190)
Other operating expenses	—	(601,648)	—	(601,648)
Gain on sale of properties	—	172	—	172
Operating loss	(20,847)	(40,151)	—	(60,998)
Equity in earnings of subsidiaries	28,269	—	(28,269)	—
Interest expense, net of capitalized interest	(103,435)	(9,267)	—	(112,702)
Other income (expense)	5	111,650	—	111,655
Income (loss) before income taxes	(96,008)	62,232	(28,269)	(62,045)
Income tax benefit (expense)	51,792	(33,963)	—	17,829
Net income (loss)	$(44,216)	$28,269	$(28,269)	$(44,216)

Condensed Consolidating Statement of Operations

	Nine Months Ended September 30, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Total revenues	$—	$1,090,556	$—	$1,090,556
General and administrative expenses	(17,790)	(50,396)	—	(68,186)
Other operating expenses	—	(579,718)	—	(579,718)
Gain on sale of properties	—	187,076	—	187,076
Operating income (loss)	(17,790)	647,518	—	629,728
Equity in earnings of subsidiaries	410,775	—	(410,775)	—
Interest expense, net of capitalized interest	(110,853)	(7,715)	—	(118,568)
Other income (expense)	3	20,500	—	20,503
Income before income taxes	282,135	660,303	(410,775)	531,663
Income tax benefit (expense)	48,238	(249,528)	—	(201,290)
Net income	$330,373	$410,775	$(410,775)	$330,373

Condensed Consolidating Statement of Cash Flows

	Nine Months Ended September 30, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$3,323	$277,014	$—	$280,337
Cash flows from investing activities:				
Capital expenditures	—	(740,633)	—	(740,633)

Derivative settlements	—	291,436	—	291,436
Other investing activities	—	(1,161)	—	(1,161)
Net cash used in investing activities	—	(450,358)	—	(450,358)
Cash flows from financing activities:				
Proceeds from sale of common stock	462,833	—	—	462,833
Proceeds from revolving credit facility	—	618,000	—	618,000
Principal payments on revolving credit facility	—	(938,000)	—	(938,000)
Other financing activities	(466,175)	459,817	—	(6,358)
Net cash provided by (used in) financing activities	(3,342)	139,817	—	136,475
Decrease in cash and cash equivalents	(19)	(33,527)	—	(33,546)
Cash and cash equivalents at beginning of period	776	45,035	—	45,811
Cash and cash equivalents at end of period	$757	$11,508	$—	$12,265

Condensed Consolidating Statement of Cash Flows

	Nine Months Ended September 30, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Net cash provided by (used in) operating activities	$(64,099)	$737,591	$—	$673,492
Cash flows from investing activities:				
Capital expenditures	—	(998,889)	—	(998,889)
Proceeds from sale of properties	—	324,938	—	324,938
Other investing activities	—	(33,163)	—	(33,163)
Net cash used in investing activities	—	(707,114)	—	(707,114)
Cash flows from financing activities:				
Proceeds from revolving credit facility	—	370,000	—	370,000
Principal payments on revolving credit facility	—	(355,570)	—	(355,570)
Other financing activities	30,599	(36,114)	—	(5,515)
Net cash provided by (used in) financing activities	30,599	(21,684)	—	8,915
Increase (decrease) in cash and cash equivalents	(33,500)	8,793	—	(24,707)
Cash and cash equivalents at beginning of period	34,277	57,624	—	91,901
Cash and cash equivalents at end of period	$777	$66,417	$—	$67,194

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16. Subsequent Events

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

Credit facility borrowing base. On October 6, 2015, the Lenders completed their regular semi-annual redetermination of the borrowing base of the Second Amended Credit Facility, resulting in a borrowing base decrease from $1,700.0 million to $1,525.0 million, which equals the Lenders' current aggregate elected commitment.

Consent solicitations. On October 26, 2015, the Company, the Company's Guarantors, and U.S. Bank National Association, as trustee, entered into supplemental indentures respecting amendments (the "Amendments") to the Indentures governing the Company's outstanding 7.25% senior unsecured notes due 2019, 6.5% senior unsecured notes due 2021 and 6.875% senior unsecured notes due 2023 (collectively, the "Consent Notes") following the Company's receipt of requisite consents of the holders of the Consent Notes pursuant to consent solicitations that commenced on October 6, 2015.

The Amendments amend the basket for secured credit facilities indebtedness in each of the Indentures by (i) adding a provision that allows the Company to incur secured credit facilities indebtedness up to the amount of the Company's borrowing base at the time of the incurrence, but not to exceed the current borrowing base of $1,525.0 million and (ii) adding, deleting or revising several related definitions in the Indentures, which changes generally restrict the Company's ability to incur second-lien indebtedness.

Derivative instruments. In October 2015, the Company entered into new swap agreements with a weighted average price of $52.19 per barrel for total notional amounts of 120,000 barrels, 3,139,000 barrels, 1,615,000 barrels and 124,000 barrels, which settle in 2015, 2016, 2017 and 2018, respectively, based on the WTI crude oil index price. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

Drilling contracts. In October 2015, the Company extended a drilling rig contract, increasing the amount the Company would be obligated to pay in the event of early termination under its drilling rig contracts with initial terms greater than one year to $7.1 million as of October 1, 2015 for the days remaining through the end of the contracts.

Volume commitment agreements. In October and November 2015, the Company entered into new sales agreements with an aggregate requirement to deliver approximately 7.1 MMBbl within specified timeframes, all of which are less than two years. The future commitment under these agreements is based on WTI at the time of delivery, and therefore, cannot be estimated.

Cost sharing agreements. In October 2015, the Company entered into an additional agreement to share the cost to construct and install electrical facilities. The Company's estimated future commitment under this agreement was $4.9 million.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with "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, 2014 ("2014 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 ("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," "potential," "pr 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 Item 1A. "Risk Factors" in our 2014 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 well services and midstream companies;
- infrastructure for salt water disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- property acquisitions;
- integration and benefits of property acquisitions or the effects of such acquisitions on our cash position and levels of indebtedness;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- our financial strategy, budget, projections, execution of business plan and operating results;
- cash flows and liquidity;
- oil and natural gas realized prices;
- general economic conditions;
- operating environment, including inclement weather conditions;
- effectiveness of risk management activities;
- competition in the oil and natural gas industry;
- counterparty credit risk;
- environmental liabilities;
- governmental regulation and the taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;
- technology;
- uncertainty regarding future operating results; and

• plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Quarterly Report on Form 10-Q. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report on Form 10-Q are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. Some of the key factors which could cause actual results to vary from

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our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Quarterly Report on Form 10-Q, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Overview

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

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

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

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

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments as well as competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Crude oil prices declined significantly in the latter part of 2014 and have remained low in 2015. As a result of lower oil prices, we have significantly decreased our planned 2015 capital expenditures as compared to 2014, and we are currently concentrating our drilling activities in certain areas that are the most economic in the Williston Basin. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

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, including the recent substantial decline in oil prices since June 2014 caused by the current oversupply of crude oil. We enter into crude oil sales contracts with purchasers who have access to crude oil transportation capacity, utilize derivative financial instruments to manage our commodity price risk and enter into physical delivery contracts to manage our price differentials. 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. 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. As of September 30, 2015, we were flowing 79% of our gross operated oil production through these gathering systems.

Changes in commodity prices may significantly impact our estimates of oil and natural gas reserves, which are estimated and reported as of December 31 of each calendar year. Our estimated net proved reserves at December 31, 2014 were determined using unweighted arithmetic average first-day-of-the-month prices for the prior twelve months of $95.28/Bbl for oil and $4.35/MMBtu for natural gas. If commodity prices remain at current levels, while assuming all other inputs remain constant, we expect a material price related revision to our previously reported estimated net proved reserves, most significantly, but not limited to, removing the majority of our proved undeveloped reserves in areas outside of our core acreage within the Williston Basin, which make up approximately 47% of our estimated proved undeveloped reserves at December 31, 2014. The lower commodity prices will also reduce our estimated proved developed reserves through higher abandonment rates. We are still in the initial stages of our year-end reserves estimation process with our independent reserve engineers, including aligning our proved undeveloped reserves with our anticipated five-year drilling plan and accounting for current year activity. We are also awaiting final year-end pricing as well as revised differentials, capital costs and operating expense assumptions, all of which have significantly decreased since year-end 2014 as a result of lower oil prices. Therefore, we are unable to quantify the amount of future reserve revisions at this time.

However, if we reduced the twelve-month average price to $50.35/Bbl for oil and $2.69/MMBtu for natural gas, holding all other factors constant, then our estimated net proved reserves would have been reduced by approximately 33%, including a 10% reduction of proved developed reserves and a 60% reduction of proved undeveloped reserves, from our reported estimated net proved reserves at December 31, 2014. The foregoing prices were calculated using the unweighted arithmetic average first-day-of-the-month prices for each of the ten months ended October 2015, with the prices for October 1, 2015 held constant for the remaining two months to create a twelve-month period. Price is only one variable in the estimation of our net proved reserves. There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in subsequent periods. As such, this decrease should not be construed as indicative of our final year-end reserve estimation process, which as noted above, is still in its initial phase.

Forward commodity prices and estimates of future production also play a significant role in determining impairment of proved oil and natural gas properties. As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to review our proved oil and natural gas properties for impairment. In the fourth quarter of 2014, we recorded an impairment loss of $40.0 million due to lower expected future oil prices. No impairment of proved oil and natural gas properties was recorded during the three and nine months ended September 30, 2015, although the difference between the expected undiscounted future cash flows and the carrying value of our proved oil and natural gas properties has narrowed as of September 30, 2015. At December 31, 2014, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations by $2,881.0 million, or 71%. This excess has decreased to $68.5 million, or 2%, as of September 30, 2015. The key assumptions used to determine the undiscounted future cash flows include estimates of future production, future commodity pricing, differentials, net estimated operating costs and anticipated capital expenditures, all of which have decreased from December 31, 2014 to September 30, 2015, and new wells on production which have increased from December 31, 2014 to September 30, 2015. Future commodity pricing is based on five-year WTI strip prices, which decreased 20% from an average of $64.74/Bbl at December 31, 2014 to an average of $51.67/Bbl at September 30, 2015, and on five-year Henry Hub strip prices, which decreased 21% from an average of $3.67/MMBtu at December 31, 2014 to an average of $2.91/MMBtu at September 30, 2015. As part of our year-end reserves estimation process, we expect changes in the key assumptions used, which could be significant, including updates to future production estimates to align with our anticipated five-year drilling plan and changes in our differentials, capital costs and operating expense assumptions, which we expect to decrease further as a result of sustained lower commodity prices. Therefore, even if forward commodity prices remain at current levels, we are unable to quantify the amount of impairment of our proved oil and natural gas properties, if any, at this time until our year-end reserves estimation process is complete.

Changes in commodity prices may also significantly affect the economic viability of drilling projects and economic recovery of oil and natural gas reserves. Higher oil prices in 2010 to 2014, as well as continued successes in the application of completion technologies in the Bakken and Three Forks formations, caused the active drilling rig count in the Williston Basin to increase to over 200 rigs during 2014. However, the active rig count has decreased to less than 65 in October 2015 due to the substantial decline in oil prices. Although Williston Basin transportation takeaway capacity, including expanded rail and pipeline infrastructure, was added from 2011 to 2014, production also increased due to the elevated drilling activity during these years, resulting in price differentials in a historical average range of approximately 10% to 15% of the NYMEX West Texas Intermediate crude oil index prices (“WTI”). At the beginning of 2014, our average price differentials to WTI were elevated due to the pipeline market weakening as a result of refinery down time and increased United States and Canadian production. In the second and third quarters of 2014, stronger pipeline prices shifted more of our barrels towards the pipelines,

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but rail buyers had to compete with pipeline prices despite weaker Brent differentials. As a result, our price differentials to WTI returned to approximately 9% to 11%. In the fourth quarter of 2014, as WTI declined, our price differentials increased as a percentage of WTI but remained relatively flat in terms of the dollar per barrel discount to WTI in the range of $9.00 to $10.50 per barrel of oil. In the first quarter of 2015, as WTI further declined, our price differentials continued to increase as a percentage of WTI but decreased in terms of the dollar per barrel discount to WTI to an average of $7.85 per barrel of oil. In the second quarter of 2015, as WTI improved, our price differentials returned to approximately 10% as a percentage of WTI and continued to decrease in terms of the dollar per barrel discount to WTI to an average of $5.90 per barrel of oil. In the third quarter of 2015, as WTI continued to decline, our price differentials remained consistent at approximately 10% as a percentage of WTI and continued to decrease in terms of the dollar per barrel discount to WTI to an average of $4.82 per barrel of oil. We expect our price differential to WTI to strengthen in the fourth quarter of 2015 and range between $4.00 and $5.00 per Boe. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations.

Third Quarter 2015 Highlights:

- Average daily production was 50,546 Boe per day during the three months ended September 30, 2015;
- We completed and placed on production 20 gross (15.4 net) operated wells in the Williston Basin during the three months ended September 30, 2015;
- For the three months ended September 30, 2015, total capital expenditures were $78.1 million;
- We decreased lease operating expenses to $7.67 per Boe for the three months ended September 30, 2015;
- At September 30, 2015, we had $12.3 million of cash and cash equivalents and had total liquidity of $1,352.1 million, including the availability under our revolving credit facility; and
- Adjusted EBITDA, a non-GAAP financial measure, was $189.2 million for the three months ended September 30, 2015. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities, see “Non-GAAP Financial Measures” below.

Results of Operations

Revenues

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

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Change	2015	2014	Change
Operating results (in thousands):						
Revenues						
Oil	$169,672	$328,548	$(158,876)	$542,049	$972,338	$(430,289)
Natural gas	5,598	16,158	(10,560)	21,190	58,397	(37,207)
Well services and midstream	21,965	23,953	(1,988)	44,429	59,821	(15,392)
Total revenues	$197,235	$368,659	$(171,424)	$607,668	$1,090,556	$(482,888)
Production data:						
Oil (MBbls)	4,077	3,769	308	12,107	10,759	1,348
Natural gas (MMcf)	3,438	2,707	731	9,940	7,752	2,188
Oil equivalents (MBoe)	4,650	4,220	430	13,764	12,051	1,713
Average daily production (Boe/d)	50,546	45,873	4,673	50,418	44,143	6,275
Average sales prices:						
Oil, without derivative settlements (per Bbl)	$41.61	$87.17	$(45.56)	$44.77	$90.37	$(45.60)
Oil, with derivative settlements (per Bbl)(1)	60.77	84.22	(23.45)	68.84	88.07	(19.23)
Natural gas (per Mcf)(2)	1.63	5.97	(4.34)	2.13	7.53	(5.40)

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

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

Three months ended September 30, 2015 as compared to three months ended September 30, 2014

Our total revenues decreased $171.4 million, or 46%, to $197.2 million during the three months ended September 30, 2015 as compared to the three months ended September 30, 2014, primarily due to lower realized oil and natural gas sales prices, partially offset by increased production volumes sold. Our average realized prices for oil and natural gas decreased by 52% and 73%, respectively, during the three months ended September 30, 2015 as compared to the three months ended September 30, 2014.

Oil and gas revenues. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 4,673 Boe per day, or 10%, to 50,546 Boe per day during the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The increase in average daily production sold was primarily a result of our 87.5 total net well completions in the Williston Basin during the twelve months ended September 30, 2015, offset by the decline in production in wells that were producing as of September 30, 2014. Average oil sales prices, without derivative settlements, decreased by $45.56/Bbl to an average of $41.61/Bbl, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, decreased by $4.34/Mcf to an average of $1.63/Mcf for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The lower oil and natural gas sales prices decreased revenues by $183.4 million, partially offset by higher production amounts sold, which increased revenues by $14.0 million during the three months ended September 30, 2015 as compared to the three months ended September 30, 2014.

Well services and midstream revenues. Well services revenues decreased $5.5 million to $15.4 million for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014 primarily due to a $8.8 million decrease in well completion product sales to third parties as a result of OWS completing substantially all of OPNA’s operated wells, offset by an increase of $5.0 million in well completion revenue as a result of OWS completing OPNA wells with a higher average third-party working interest. Midstream revenues were $6.6 million for the three months ended September 30, 2015, which was a $3.6 million increase quarter over quarter, primarily due to increased water volumes flowing through our salt water disposal systems and increased fresh water sales.

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Nine months ended September 30, 2015 as compared to nine months ended September 30, 2014

Our total revenues decreased $482.9 million, or 44%, to $607.7 million during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014, primarily due to lower realized oil and natural gas sales prices, partially offset by increased production volumes sold. Our average realized prices for oil and natural gas decreased by 50% and 72%, respectively, during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014.

Oil and gas revenues. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 6,275 Boe per day, or 14%, to 50,418 Boe per day during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. The increase in average daily production sold was primarily a result of our 87.5 total net well completions in the Williston Basin during the twelve months ended September 30, 2015, offset by the decline in production in wells that were producing as of September 30, 2014. Average oil sales prices, without derivatives settlements, decreased by $45.60/Bbl to an average of $44.77/Bbl, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, decreased by $5.40/Mcf to an average of $2.13/Mcf for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. The lower oil and natural gas sales prices decreased revenues by $532.5 million, partially offset by higher production amounts sold, which increased revenues by $65.0 million during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014.

Well services and midstream revenues. Well services revenues decreased $24.3 million to $27.3 million for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014 primarily due to a $18.8 million decrease in well completion product sales to third parties as a result of OWS completing substantially all of OPNA’s operated wells. In addition, well completion revenue decreased $3.2 million as a result of OWS completing OPNA wells with a lower average third-party working interest, offset by increased well completion activity in the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. While a lower average third-party working interest decreases the well completion revenue recognized in our consolidated results of operations, it improves our capital expenditures by reducing OPNA well costs. Midstream revenues were $17.1 million for the nine months ended September 30, 2015, which was a $8.9 million increase period over period, primarily due to increased water volumes flowing through our salt water disposal systems and increased fresh water sales.

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Expenses and other income

The following table summarizes our operating expenses, gain on sale of properties and other income and expenses for the periods presented:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Change	2015	2014	Change
	(In thousands, except per Boe of production)					
Operating expenses:						
Lease operating expenses	$35,670	$44,361	$(8,691)	$112,556	$124,903	$(12,347)
Well services and midstream operating expenses	10,023	14,922	(4,899)	19,370	34,611	(15,241)
Marketing, transportation and gathering expenses	8,465	7,306	1,159	23,313	19,606	3,707
Production taxes	16,676	34,584	(17,908)	53,915	100,880	(46,965)
Depreciation, depletion and amortization	123,734	106,972	16,762	361,430	295,520	65,910
Exploration expenses	327	1,100	(773)	2,252	1,955	297
Rig termination	—	—	—	3,895	—	3,895
Impairment of oil and gas properties	80	1,439	(1,359)	24,917	2,243	22,674
General and administrative expenses	22,358	23,915	(1,557)	67,190	68,186	(996)
Total operating expenses	217,333	234,599	(17,266)	668,838	647,904	20,934
Gain on sale of properties	172	43	129	172	187,076	(186,904)
Operating income (loss)	(19,926)	134,103	(154,029)	(60,998)	629,728	(690,726)
Other income (expense):						
Net gain on derivative instruments	103,637	103,426	211	111,285	20,253	91,032
Interest expense, net of capitalized interest	(36,513)	(39,420)	2,907	(112,702)	(118,568)	5,866
Other income (expense)	249	(38)	287	370	250	120
Total other income (expense)	67,373	63,968	3,405	(1,047)	(98,065)	97,018
Income (loss) before income taxes	47,447	198,071	(150,624)	(62,045)	531,663	(593,708)
Income tax benefit (expense)	(20,392)	(76,484)	56,092	17,829	(201,290)	219,119
Net income (loss)	$27,055	$121,587	$(94,532)	$(44,216)	$330,373	$(374,589)
Costs and expenses (per Boe of production):						
Lease operating expenses	$7.67	$10.51	$(2.84)	$8.18	$10.36	$(2.18)
Marketing, transportation and gathering expenses	1.82	1.73	0.09	1.69	1.63	0.06
Production taxes	3.59	8.19	(4.60)	3.92	8.37	(4.45)
Depreciation, depletion and amortization	26.61	25.35	1.26	26.26	24.52	1.74
General and administrative expenses	4.81	5.67	(0.86)	4.88	5.66	(0.78)

Three months ended September 30, 2015 as compared to three months ended September 30, 2014

Lease operating expenses. Lease operating expenses decreased $8.7 million to $35.7 million for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. This decrease was primarily due to lower workover costs and an increase in salt water disposal volumes being transported on OMS pipelines and injected in OMS salt water disposal wells, partially offset by higher costs associated with operating an increased number of producing wells. Lease operating expenses decreased from $10.51 per Boe for the three months ended September 30, 2014 to $7.67 per Boe for the three months ended September 30, 2015 due to the lower costs and increase in oil and natural gas production.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs and cost of goods sold incurred by OWS and OMS. The $4.9 million decrease for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014 was attributable to a $5.1 million decrease in well completion costs as a result of lower well completion product sales to third parties due to OWS completing substantially all of OPNA's operated wells, offset by an increase in well completion costs as a result of OWS completing OPNA wells with a higher average third-party working interest. This net decrease was partially offset by a $0.2 million increase in operating expenses related to midstream services.

Marketing, transportation and gathering expenses. The $1.2 million increase in marketing, transportation and gathering expenses for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014 was primarily attributable to a $0.6 million increase in the pipeline imbalance accrual and a $0.5 million increase in gas gathering charges related to additional well connections on OMS infrastructure.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 9.5% and 10.0%, respectively, for the three months ended September 30, 2015 and 2014. The production tax rate was lower for the three months ended September 30, 2015 and 2014 primarily due to incentivized production tax rates triggered by lower oil prices on certain North Dakota wells. For the three months ended September 30, 2015 and 2014, the percentage of our total production located in North Dakota was 89% and 87%, respectively, with an average production tax rate of approximately 10%, as compared to a 6% average production tax rate on our production in Montana.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $16.8 million to $123.7 million for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. This increase in DD&A expense for the three months ended September 30, 2015 was a result of production increases from our wells completed during the twelve months ended September 30, 2015. The DD&A rate for the three months ended September 30, 2015 was $26.61 per Boe compared to $25.35 per Boe for the three months ended September 30, 2014. The increase in the DD&A rate was primarily due to lower recoverable reserves related to lower oil and natural gas prices and increased exploratory and delineation drilling in the Three Forks formation.

Impairment of oil and gas properties. During the three months ended September 30, 2015 and 2014, we recorded non-cash impairment charges of $0.1 million and $1.4 million respectively, for unproved properties due to leases that expired during the period. As a result of periodic assessments of unproved properties not held-by-production, during the fourth quarter of 2014 and the first half of 2015, we recorded non-cash impairment charges of $3.8 million related to leases that expired during the three months ended September 30, 2015. We recorded these impairment charges in prior quarters because there were no plans to drill or extend the leases prior to their expiration. This resulted in lower impairment expense in the third quarter of 2015 compared to the third quarter of 2014, which included impairment expense for all leases that expired during that period. No impairment charges of proved oil and gas properties were recorded for the three months ended September 30, 2015 or 2014.

General and administrative ("G&A") expenses. Our G&A expenses decreased $1.6 million to $22.4 million for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. E&P G&A was $18.9 million and $20.9 million for the three months ended September 30, 2015 and 2014, respectively. The $2.0 million decrease in E&P G&A was primarily due to increased shared services allocations to the OWS and OMS segments coupled with decreases in consulting services, contract labor and recruiting costs period over period. G&A for our OWS and OMS segments increased by $0.3 million and $0.1 million, respectively, for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The increase in OWS and OMS G&A was primarily due to increased employee compensation expense due to organizational growth within these segments.

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $103.6 million net gain on derivative instruments, including net cash settlement receipts of $78.1 million, for the three months ended September 30, 2015, and a $103.4 million net gain on derivative instruments, including net cash settlement payments of $11.1 million for the three months ended September 30, 2014. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Interest expense. Interest expense decreased $2.9 million to $36.5 million for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The decrease was primarily the result of increased interest costs capitalized, partially offset by an increase in interest expense incurred on borrowings under our revolving credit facility. Interest capitalized during the three months ended September 30, 2015 and 2014 was $5.1 million and $2.3 million, respectively. The increase in interest capitalized was due to increased accumulated capital expenditures for assets not yet placed into production in the third quarter of 2015 as compared to the third quarter of

2014. For the three months ended September 30, 2015 and 2014, the weighted average debt outstanding under our revolving credit facility was $205.9 million and $249.6 million, respectively. The weighted average interest rate incurred on the outstanding borrowings was 1.7% for each of the three months ended September 30, 2015 and 2014.
Income taxes. Income tax expense for the three months ended September 30, 2015 and 2014 was recorded at 43.0% and 38.6% of pre-tax net income, respectively. While our effective tax rate for the three months ended September 30, 2014 was consistent with the statutory tax rate applicable to the U.S. and the blended state rate for the states in which we conduct

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business, the effective tax rate for the three months ended September 30, 2015 was higher due to lower pre-tax income and the impact of permanent differences between the compensation amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vestings during the third quarter of 2015 at stock prices lower than the grant date values, partially offset by a reduction in the North Dakota statutory tax rate in the second quarter of 2015.

Nine months ended September 30, 2015 as compared to nine months ended September 30, 2014

Lease operating expense. Lease operating expenses decreased $12.3 million to $112.6 million for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. The decrease was primarily due to lower workover costs and an increase in salt water disposal volumes being transported on OMS pipelines and injected in OMS salt water disposal wells, partially offset by higher costs associated with operating an increased number of producing wells. Lease operating expenses decreased from $10.36 per Boe for the nine months ended September 30, 2014 to $8.18 per Boe for the nine months ended September 30, 2015 due to the increase in oil and natural gas production and lower costs.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs and cost of goods sold incurred by OWS and OMS. The $15.2 million decrease for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014 was attributable to a $16.2 million decrease in well completion costs as a result of lower well completion product sales to third parties due to OWS completing substantially all of OPNA's operated wells and OWS completing OPNA wells with a lower average third-party working interest in the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. This decrease was partially offset by a $1.0 million increase in operating expenses related to midstream services.

Marketing, transportation and gathering expenses. The $3.7 million increase in marketing, transportation and gathering expenses for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014 was primarily attributable to a a $1.2 million increase in gas gathering charges related to additional well connections on OMS infrastructure, a $1.2 million increase in the pipeline imbalance accrual and a $1.2 million increase in oil transportation costs associated with having additional wells connected to third-party infrastructure. The transporting of volumes through third-party oil gathering pipelines increases marketing transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 9.6% and 9.8%, respectively for the nine months ended September 30, 2015 and 2014. The production tax rate remained stable for the nine months ended September 30, 2015 and 2014 primarily due to our production weighting remaining consistent between North Dakota and Montana in the comparative periods. For the nine months ended September 30, 2015 and 2014, the percentage of our total production located in North Dakota was 87% and 86%, respectively, with an average production tax rate of approximately 10%, as compared to a 5% average production tax rate on our production in Montana.

Depreciation, depletion, and amortization. DD&A expense increased $65.9 million to $361.4 million for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. The increase in DD&A expense for the nine months ended September 30, 2015 was a result of production increases from our wells completed during the twelve months ended September 30, 2015. The DD&A rate for the nine months ended September 30, 2015 was $26.26 per Boe compared to $24.52 per Boe for the nine months ended September 30, 2014. The increase in the DD&A rate was primarily due to lower recoverable reserves related to lower oil and natural gas prices and increased exploratory and delineation drilling in the Three Forks formation.

Impairment of oil and gas properties. During the nine months ended September 30, 2015 and 2014, we recorded non-cash impairment charges of $24.9 million and $2.2 million, respectively, for unproved properties due to leases that expired during the period and periodic assessments of unproved properties not held-by-production. The impairment charges for the nine months ended September 30, 2015 included $16.4 million related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. No impairment charges of proved oil and gas properties were recorded for the nine months ended September 30, 2015 or

2014.

General and administrative expenses. Our G&A expenses decreased $1.0 million for the nine months ended September 30, 2015 from $68.2 million for the nine months ended September 30, 2014. E&P G&A was $61.0 million and $61.5 million for the nine months ended September 30, 2015 and 2014, respectively. The $0.5 million decrease in E&P G&A was primarily due to increased shared services allocations to the OWS and OMS segments. OWS G&A decreased by $1.5 million primarily due to OWS completing OPNA wells with a lower average third-party working interest in the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. OMS G&A increased $1.0 million for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014 primarily due to increased employee compensation expense due to organizational growth within this segment.

Gain on sale of properties. During the nine months ended September 30, 2015, we recognized a gain on sale of properties of $0.2 million related to the sale of certain non-operated properties in and around our Sanish position ("the Sanish Divestiture") and the sale of working interests in certain non-operated properties. During the nine months ended September 30, 2014, we recognized a gain on sale of properties of $187.0 million for the Sanish Divestiture.

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $111.3 million net gain on derivative instruments, including net cash settlement receipts of $291.4 million, for the nine months ended September 30, 2015, and a $20.3 million net gain on derivative instruments, including net cash settlement payments of $24.8 million for the nine months ended September 30, 2014. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Interest expense. Interest expense decreased $5.9 million to $112.7 million for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. The decrease was primarily the result of increased interest costs capitalized, partially offset by an increase in the interest expense incurred on borrowings under our revolving credit facility. Interest capitalized during the nine months ended September 30, 2015 and 2014 was $13.8 million and $6.1 million, respectively. The increase in interest capitalized was due to increased accumulated capital expenditures for assets not yet placed into production in the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. For the nine months ended September 30, 2015 and 2014, the weighted average debt outstanding under our revolving credit facility was $844.9 million and $209.0 million, respectively, and the weighted average interest rate incurred on the outstanding borrowings was 1.8% and 1.7%, respectively.

Income taxes. Income tax expense for the nine months ended September 30, 2015 and 2014 was recorded at 28.7% and 37.9% of pre-tax net income, respectively. While our 2014 rate was consistent with the statutory tax rate applicable to the U.S. and the blended state rate for the states in which we conduct business, our effective tax rate for the nine months ended September 30, 2015 was lower due to permanent differences between the compensation amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vestings during the nine months ended September 30, 2015 at stock prices lower than the grant date values, partially offset by a reduction in the North Dakota statutory tax rate in the second quarter of 2015.

Liquidity and Capital Resources

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

Our cash flows for the nine months ended September 30, 2015 and 2014 are presented below:

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
Net cash provided by operating activities	$280,337	$673,492
Net cash used in investing activities	(450,358)	(707,114)
Net cash provided by financing activities	136,475	8,915
Decrease in cash and cash equivalents	$(33,546)	$(24,707)

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 prices on a portion of our production, thereby mitigating our exposure to oil price declines, but these transactions may also limit our cash flow in periods of rising oil prices. Prices for oil declined significantly in the fourth quarter of 2014 and into 2015, which has substantially decreased our cash flows provided by operating activities. The decline in operating cash flows caused by lower oil prices is partially offset by cash flows from our derivative contracts. On March 9, 2015, we completed a public equity offering resulting in net proceeds of $463.1 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we used to repay outstanding indebtedness under our revolving credit facility and for general corporate purposes. Our existing revolving credit facility provides additional liquidity, and after the borrowing base redetermination on October 6, 2015, our aggregate elected commitment amount remained at $1,525.0 million. We believe we have adequate liquidity to fund our remaining 2015 and expected 2016 capital expenditures and to meet our near-term future obligations. 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 $280.3 million and $673.5 million for the nine months ended September 30, 2015 and 2014, respectively. The decrease in cash flows provided by operating activities for the period ended September 30, 2015 as compared to 2014 was primarily the result of lower realized oil and natural gas sales prices coupled with decreases in well completion product sales to third parties and well completion revenue, offset by our 14% increase in oil and natural gas production and increases in salt water transport, salt water disposal and fresh water sales.

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 $52.3 million at September 30, 2015. We believe we have adequate liquidity to meet our working capital requirements. As of September 30, 2015, we had $1,352.1 million of liquidity available, including $12.3 million in cash and cash equivalents and $1,339.8 million of unused borrowing base committed capacity available under our revolving credit facility. At September 30, 2014, we had a working capital deficit of $137.9 million.

Cash flows used in investing activities

Net cash used in investing activities was $450.4 million and $707.1 million during the nine months ended September 30, 2015 and 2014, respectively. Net cash used in investing activities during the nine months ended September 30, 2015 was primarily attributable to $740.6 million in capital expenditures primarily for drilling and development costs, partially offset by $291.4 million of derivative settlements received as a result of lower crude oil pricing. Net cash used in investing activities during the nine months ended September 30, 2014 was primarily attributable to $972.8 million in capital expenditures primarily for drilling and development costs, partially offset by proceeds of $324.9 million related to the Sanish Divestiture.

Our capital expenditures are summarized in the following table:

	Nine Months Ended September 30, 2015 (In thousands)
Capital expenditures:	
E&P (including OMS)	$478,677
OWS	21,724
Other capital expenditures[1]	19,165
Total capital expenditures[2]	$519,566

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

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

Our total 2015 capital expenditure budget is $705 million, which includes $678 million for E&P capital expenditures and $27 million for non-E&P capital expenditures, including OWS, administrative capital and capitalized interest. Our planned E&P capital expenditures include $565 million of drilling and completion (including production-related equipment) capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS and OMS).

While we have budgeted $705 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 budgeted. With our current pace of completions coupled with our lower well costs as of September 30, 2015, we are currently planning to invest approximately $670 million in total capital expenditures during 2015, as compared to our approved budget of $705 million. We believe that cash on hand, cash flows from operating activities, proceeds from cash settlements under our derivative contracts and availability under our revolving credit facility should be sufficient to fund our 2015 capital expenditure budget. However, because the operated wells funded by our 2015 drilling plan represent only a small percentage of our gross potential drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of potential drilling locations should we elect to do so.

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

Cash flows provided by financing activities

Net cash provided by financing activities was $136.5 million and $8.9 million for the nine months ended September 30, 2015 and 2014, respectively. For the nine months ended September 30, 2015, cash provided by financing activities was primarily due to net proceeds from the issuance of our common stock and proceeds from borrowings under our revolving credit facility, partially offset by principal payments on our revolving credit facility. Net cash provided by financing activities during the nine months ended September 30, 2014 was primarily due to proceeds from borrowings under our revolving credit facility, partially offset by principal payments on our revolving credit facility. For both the nine months ended September 30, 2015 and 2014, cash was used in financing activities for the purchases of treasury stock for shares withheld by us equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards.

Sale of common stock. On March 9, 2015, we completed a public offering of 36,800,000 shares of our common stock at an offering price of $12.80 per share. We used the net proceeds from the offering of $463.1 million, after deducting underwriting discounts and commissions and estimated offering expenses, to repay outstanding indebtedness under our revolving credit facility and for general corporate purposes.

Senior unsecured notes. On September 24, 2013, we issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the “2022 Notes”). Interest is payable on the 2022 Notes semi-annually in arrears on each March 15 and September 15, commencing March 15, 2014. The issuance of these 2022 Notes resulted in net proceeds to us of $983.6 million, which we used to fund a portion of our 2013 acquisitions of oil and gas properties.

At any time prior to September 15, 2016, we may redeem up to 35% of the 2022 Notes at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding after such redemption. Prior to September 15, 2017, we may redeem some or all of the 2022 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after September 15, 2017, we may redeem some or all of the 2022 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.438% for the twelve-month period beginning on September 15, 2017, 101.719% for the twelve-month period beginning on September 15, 2018 and 100.00% beginning on September 15, 2019, plus accrued and unpaid interest to the redemption date.

On July 2, 2012, we issued $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the “2023 Notes”). Interest is payable on the 2023 Notes semi-annually in arrears on each January 15 and July 15, commencing January 15, 2013. The issuance of these 2023 Notes resulted in net proceeds to us of $392.4 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

Prior to July 15, 2017, we may redeem some or all of the 2023 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after July 15, 2017, we may redeem some or all of the 2023 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.438% for the twelve-month period beginning on July 15, 2017, 102.292% for the twelve-month period beginning on July 15, 2018, 101.146% for the twelve-month period beginning

on July 15, 2019 and 100.00% beginning on July 15, 2020, plus accrued and unpaid interest to the redemption date.
On November 10, 2011, we issued $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the "2021 Notes"). Interest is payable on the 2021 Notes semi-annually in arrears on each May 1 and November 1, commencing May 1, 2012. The issuance of these 2021 Notes resulted in net proceeds to us of $393.4 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.
Prior to November 1, 2016, we may redeem some or all of the 2021 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and

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after November 1, 2016, we may redeem some or all of the 2021 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.25% for the twelve-month period beginning on November 1, 2016, 102.167% for the twelve-month period beginning on November 1, 2017, 101.083% for the twelve-month period beginning on November 1, 2018 and 100.00% beginning on November 1, 2019, plus accrued and unpaid interest to the redemption date.

On February 2, 2011, we issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”). Interest is payable on the 2019 Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The issuance of these 2019 Notes resulted in net proceeds to us of $390.0 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes. We may redeem some or all of the 2019 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning on February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

The 2019 Notes, 2021 Notes, 2022 Notes and 2023 Notes (collectively, the “Notes”) are guaranteed on a senior unsecured basis by our material subsidiaries (the “Guarantors”). The indentures governing the Notes restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when our Notes are rated investment grade by both Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no Default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

On October 26, 2015, we, along with our Guarantors, and U.S. Bank National Association, as trustee, entered into supplemental indentures respecting amendments (the “Amendments”) to the indentures governing our outstanding 7.25% senior unsecured notes due 2019, 6.5% senior unsecured notes due 2021 and 6.875% senior unsecured notes due 2023 (collectively, the “Consent Notes”) following the our receipt of requisite consents of the holders of the Consent Notes pursuant to consent solicitations that commenced on October 6, 2015.

The Amendments amend the basket for secured credit facilities indebtedness in each of the indentures by (i) adding a provision that allows us to incur secured credit facilities indebtedness up to the amount of our borrowing base at the time of the incurrence, but not to exceed the current borrowing base of $1,525.0 million and (ii) adding, deleting or revising several related definitions in the indentures, which changes generally restrict our ability to incur second-lien indebtedness.

Senior secured revolving line of credit. On April 5, 2013, we entered into a second amended and restated credit agreement (the “Second Amended Credit Facility”), which had a maturity date of April 5, 2018. The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On April 13, 2015, we entered into our third amendment to the Second Amended Credit Facility, which extended the maturity date of the Second Amended Credit Facility to April 13, 2020, provided that the 2019 Notes are retired or refinanced 90 days prior to the maturity of the 2019 Notes. On October 6, 2015, the lenders under our Second Amended Credit Facility (the “Lenders”) completed their regular semi-annual redetermination of the borrowing base scheduled for October 1, 2015, resulting in a borrowing base decrease from $1,700.0 million to $1,525.0 million, which is equal to the Lenders’ current aggregate elected commitment. The overall senior secured line of credit under our Second Amended Credit Facility is $2,500.0 million as of September 30, 2015. Borrowings under our Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports. At our election, interest is generally determined by reference to (i) the London interbank offered rate (“LIBOR”) plus an applicable margin between 1.50% and 2.50% per annum; or (ii) a domestic bank prime rate plus an applicable margin between 0.00% and 1.00% per annum.

As of September 30, 2015, we had $180.0 million of borrowings and $5.2 million outstanding letters of credit under our Second Amended Credit Facility, resulting in an unused borrowing base committed capacity of $1,339.8 million.

The Second Amended Credit Facility also contains certain financial covenants and customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under our Second Amended Credit Facility to be immediately due and payable. As of September 30, 2015, we were in compliance with the financial covenants of our Second Amended Credit Facility. While we expect to draw on the Second Amended Credit Facility in 2015 to fund capital expenditures, we do not expect to violate any financial covenants.

Non-GAAP Financial Measures

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Adjusted EBITDA and Adjusted Net Income are supplemental non-GAAP financial measures that are used by management and external users of our consolidated 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 net income, operating income, net cash provided by operating activities or any other measures prepared under accounting principles generally accepted in the United States of America ("GAAP"). Because Adjusted EBITDA and Adjusted Net Income exclude some but not all items that affect net income and may vary among companies, the amounts presented may not be comparable to similar metrics of other companies.

Adjusted EBITDA

We define Adjusted EBITDA as earnings before interest expense, income taxes, depreciation, depletion, amortization, exploration expenses and other similar non-cash or non-recurring charges. Adjusted EBITDA is not a measure of net income 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 and our ability to incur and service debt and to fund capital expenditures.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Net income (loss)	$27,055	$121,587	$(44,216)	$330,373
Gain on sale of properties	(172)	(43)	(172)	(187,076)
Net gain on derivative instruments	(103,637)	(103,426)	(111,285)	(20,253)
Derivative settlements[1]	78,100	(11,129)	291,436	(24,773)
Interest expense, net of capitalized interest	36,513	39,420	112,702	118,568
Depreciation, depletion and amortization	123,734	106,972	361,430	295,520
Impairment of oil and gas properties	80	1,439	24,917	2,243
Rig termination	—	—	3,895	—
Exploration expenses	327	1,100	2,252	1,955
Stock-based compensation expenses	5,966	6,077	19,629	15,755
Income tax (benefit) expense	20,392	76,484	(17,829)	201,290
Other non-cash adjustments	883	351	782	(277)
Adjusted EBITDA	$189,241	$238,832	$643,541	$733,325
Net cash provided by operating activities	$50,451	$187,238	$280,337	$673,492
Derivative settlements[1]	78,100	(11,129)	291,436	(24,773)
Interest expense, net of capitalized interest	36,513	39,420	112,702	118,568
Rig termination	—	—	3,895	—
Exploration expenses	327	1,100	2,252	1,955
Deferred financing costs amortization and other	(2,409)	(1,989)	(7,468)	(5,209)
Current tax expense	—	(2,369)	—	3,742
Changes in working capital	25,376	26,210	(40,395)	(34,173)
Other non-cash adjustments	883	351	782	(277)
Adjusted EBITDA	$189,241	$238,832	$643,541	$733,325

(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.

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

	Exploration and Production			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Income (loss) before income taxes	$29,070	$190,152	$(104,102)	$504,657
Gain on sale of properties	(172)	(43)	(172)	(187,076)
Net gain on derivative instruments	(103,637)	(103,426)	(111,285)	(20,253)
Derivative settlements[1]	78,100	(11,129)	291,436	(24,773)
Interest expense, net of capitalized interest	36,513	39,420	112,702	118,568
Depreciation, depletion and amortization	122,075	105,548	357,664	292,253
Impairment of oil and gas properties	80	1,439	24,917	2,243
Rig termination	—	—	3,895	—
Exploration expenses	327	1,100	2,252	1,955
Stock-based compensation expenses	5,761	5,877	19,276	15,398
Other non-cash adjustments	883	351	782	(277)
Adjusted EBITDA	$169,000	$229,289	$597,365	$702,695

(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.

	Well Services			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Income before income taxes	$10,950	$23,388	$29,588	$53,212
Depreciation, depletion and amortization	4,904	3,960	14,430	9,719
Stock-based compensation expenses	544	524	1,530	1,183
Adjusted EBITDA	$16,398	$27,872	$45,548	$64,114

	Midstream Services			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Income before income taxes	$18,828	$5,126	$44,039	$15,854
Depreciation, depletion and amortization	1,509	979	4,070	2,713
Stock-based compensation expenses	206	—	529	—
Adjusted EBITDA	$20,543	$6,105	$48,638	$18,567

Adjusted Net Income

We define Adjusted Net Income as net income (loss) after adjusting first for (1) the impact of certain non-cash and non-recurring items, including non-cash changes in the fair value of derivative instruments, impairment of oil and gas properties and other similar non-cash and non-recurring charges, and then (2) the non-cash and non-recurring items' impact on taxes based on our effective tax rate in the same period. Adjusted Net Income is not a measure of net income (loss) as determined by GAAP. We define Adjusted Diluted Earnings Per Share as Adjusted Net Income divided by diluted weighted average shares outstanding. Management believes that the presentation of Adjusted Net Income and Adjusted Diluted Earnings Per Share provides useful additional information to investors and analysts for evaluating our operational trends and performance.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per share data)			
Net income (loss)	$27,055	$121,587	$(44,216)	$330,373
Gain on sale of properties	(172)	(43)	(172)	(187,076)
Net gain on derivative instruments	(103,637)	(103,426)	(111,285)	(20,253)
Derivative settlements[1]	78,100	(11,129)	291,436	(24,773)
Impairment of oil and gas properties	80	1,439	24,917	2,243
Rig termination	—	—	3,895	—
Other non-cash adjustments	883	351	782	(277)
Tax impact[2]	10,635	43,560	(60,222)	87,131
Adjusted Net Income	$12,944	$52,339	$105,135	$187,368
Diluted earnings (loss) per share	$0.20	$1.21	$(0.35)	$3.29
Gain on sale of properties	—	—	—	(1.86)
Net gain on derivative instruments	(0.76)	(1.03)	(0.87)	(0.20)
Derivative settlements[1]	0.57	(0.11)	2.28	(0.25)
Impairment of oil and gas properties	—	0.01	0.19	0.02
Rig termination	—	—	0.03	—
Other non-cash adjustments	0.01	—	0.01	—
Tax impact[2]	0.07	0.44	(0.47)	0.87
Adjusted Diluted Earnings Per Share	$0.09	$0.52	$0.82	$1.87
Diluted weighted average shares outstanding	137,014	100,306	127,827	100,356
Effective tax rate	43.0%	38.6%	28.7%	37.9%

(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 on the adjustments for certain non-cash and non-recurring items.

Fair Value of Financial Instruments

See Note 5 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 2014 Annual Report.

Recent accounting pronouncements

Revenue recognition. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP. In August 2015, the

FASB issued Accounting Standards Update No. 2015-14, Deferral of the Effective Date ("ASU 2015-14"). ASU 2015-14 defers the effective date of the new revenue standard by one year, making it effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

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

Extraordinary items. In January 2015, the FASB issued Accounting Standards Update No. 2015-01, Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items ("ASU 2015-01"). ASU 2015-01 removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net-of-tax presentation will no longer be allowed. ASU 2015-01 is effective for fiscal years beginning after December 15, 2015, including interim periods within those years. We do not expect the adoption of this guidance to have a material impact on our financial position, cash flows or results of operations.

Debt issuance costs. In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, consistent with the presentation of debt discount, but it does not affect the recognition or measurement of debt issuance costs. ASU 2015-03 is effective for fiscal years beginning after December 15, 2015, including interim periods within those years, and should be applied on a retrospective basis for all prior periods presented. We expect that the adoption of this guidance will only impact the presentation of our balance sheet. As of September 30, 2015 and December 31, 2014, we had capitalized, unamortized debt issuance costs associated with debt liabilities other than line-of-credit arrangements of $25.9 million and $29.3 million, respectively, included in deferred financing costs and other assets on our Condensed Consolidated Balance Sheet. In August 2015, the FASB issued Accounting Standards Update No. 2015-15, Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements ("ASU 2015-15"), which confirms that line-of-credit arrangements are not in the scope of ASU 2015-03. ASU 2015-15 states that, for debt issuance costs related to line-of-credit arrangements, the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are outstanding borrrowings under the line-of-credit arrangement.

Inventory. In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Simplifying the Measurement of Inventory ("ASU 2015-11"). ASU 2015-11 changes the inventory measurement principle from lower of cost or market to lower of cost and net realizable value for entities using the first-in, first out (FIFO) or average cost methods. ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Business combinations. In September 2015, the FASB issued Accounting Standards Update No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments ("ASU 2015-16"), which eliminates the requirement for an acquirer in a business combination to restate prior period financial statements for measurement period adjustments. ASU 2015-16 requires that the cumulative impact of measurement period adjustments on current and prior periods be recognized in the reporting period in which the adjustment amount is determined. ASU 2015-16 is effective for fiscal years beginning after December 15, 2015, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See Note 14 to our unaudited condensed consolidated financial statements for a description of our commitments and contingencies.

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Item 3. — Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our 2014 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 prices. As of September 30, 2015, we utilized two-way costless collar options and swaps to reduce the volatility of oil prices on a significant portion of our future expected oil production. 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 swap is a sold call and a purchased put established at the same price (both ceiling and floor).

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, 2015:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices Swap	Floor	Ceiling	Fair Value
		(Barrels)	($/Barrel)			(In thousands)
2015	Two-way collars	455,000		$86.00	$103.42	$18,790
2015	Swaps	2,093,000	$73.35			57,933
2016	Two-way collars	155,000		$86.00	$103.42	6,133
2016	Swaps	5,643,000	$57.75			51,499
2017	Swaps	372,000	$53.84			1,001
						$135,356

Interest rate risk. We had (i) $400.0 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum, (ii) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum and (iii) $1,400.0 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum outstanding at September 30, 2015. At September 30, 2015, we had $180.0 million of borrowings and $5.2 million letters of credit outstanding under our Second Amended Credit Facility, which were subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a LIBOR loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or “ABR” loan). At September 30, 2015, the outstanding borrowings under our Second Amended Credit Facility bore interest at LIBOR plus a 1.5% 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 our Second Amended 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. 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. 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 our Second Amended Credit Facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the volumes placed under individual contracts.

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.

We may, from time to time, 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. Our investment policy requires that our counterparties have minimum credit ratings thresholds and provides maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers being unable to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If a commercial paper issuer is unable to return investment proceeds to us at the maturity date, it could take a significant amount of time to recover all or a portion of the assets originally invested. Our commercial paper balance was $36,000 at September 30, 2015.

Most of the counterparties on our derivative instruments currently in place are Lenders under our Second Amended Credit Facility with investment grade ratings. We are likely to enter into future derivative instruments with these or other Lenders under our Second Amended 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 asset position of $135.4 million at September 30, 2015.

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, 2015. 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, 2015.

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, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II — OTHER INFORMATION

Item 1. — Legal Proceedings

See Part I, Item 1, Note 14 to our unaudited condensed consolidated financial statements entitled "Commitments and Contingencies," which is incorporated in this item by reference.

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.

For a discussion of our potential risks and uncertainties, see the information in Item 1A. "Risk Factors" in our 2014 Annual Report. There have been no material changes in our risk factors from those described in our 2014 Annual Report.

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

Unregistered sales of 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, 2015:

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, 2015	2,025	$ 14.46	—	—
August 1 - August 31, 2015	44,547	8.80	—	—
September 1 - September 30, 2015	41,190	10.15	—	—
Total	87,762	$ 9.56	—	—

(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes needed for payroll tax withholding obligations 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.

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Item 6. — Exhibits

Exhibit No.	Description of Exhibit
4.1	Fifth Supplemental Indenture, dated as of October 26, 2015, to Indenture dated as of February 2, 2011, by and among the Company, the Guarantors, and US. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on October 30, 2015, and incorporated herein by reference).
4.2	Fourth Supplemental Indenture, dated as of October 26, 2015, to Indenture dated as of November 10, 2011, by and among the Company, the Guarantors, and US. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company’s Current Report on Form 8-K on October 30, 2015, and incorporated herein by reference).
4.3	Fifth Supplemental Indenture, dated as of October 26, 2015, to Indenture dated as of November 10, 2011, by and among the Company, the Guarantors, and US. Bank National Association, as trustee (filed as Exhibit 4.3 to the Company’s Current Report on Form 8-K on October 30, 2015, 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.

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SIGNATURES

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

		OASIS PETROLEUM INC.
Date: November 5, 2015	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)

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(b) Furnished herewith.