Atlas Resource Partners, L.P.
Form 10-Q
May 16, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2016

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	45-3591625
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Park Place Corporate Center One	15275
1000 Commerce Drive, Suite 400	

Pittsburgh, Pennsylvania
(Address of principal executive office) (Zip code)

Registrant's telephone number, including area code: (800) 251-0171

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

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

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

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

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

The number of outstanding common limited partner units of the registrant on May 12, 2016 was 102,429,220.

ATLAS RESOURCE PARTNERS, L.P.

INDEX TO QUARTERLY REPORT

ON FORM 10-Q

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	March 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$19,285	$1,353
Accounts receivable	57,152	63,367
Advances to affiliates	10,997	—
Current portion of derivative asset	159,745	159,460
Subscriptions receivable	—	19,877
Prepaid expenses and other	16,635	22,935
Total current assets	263,814	266,992
Property, plant and equipment, net	1,175,045	1,191,611
Goodwill and intangible assets, net	14,062	14,095
Long-term derivative asset	195,074	198,262
Other assets, net	31,502	28,989
Total assets	$1,679,497	$1,699,949
LIABILITIES AND PARTNERS’ CAPITAL (DEFICIT)		
Current liabilities:		
Accounts payable	$46,120	$49,249
Advances from affiliates	—	9,924
Liabilities associated with drilling contracts	—	21,483
Current portion of derivative payable to Drilling Partnerships	2,018	2,574
Accrued well drilling and completion costs	4,053	26,914
Accrued interest	10,134	25,436
Distribution payable	4,337	4,334
Accrued liabilities	18,930	22,086
Current portion of long-term debt	906,156	—
Total current liabilities	991,748	162,000
Long-term debt, less current portion, net	647,604	1,503,427

Asset retirement obligations	118,110	113,740
Other long-term liabilities	5,516	5,410
Commitments and contingencies (Note 8)		
Partners' Capital (Deficit):		
General partner's interest	(30,989)	(31,054)
Preferred limited partners' interests	188,097	188,739
Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	(257,625)	(262,864)
Accumulated other comprehensive income	15,860	19,375
Total partners' deficit	(83,481)	(84,628)
Total liabilities and partners' deficit	$1,679,497	$1,699,949

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31, 2016	2015
Revenues:		
Gas and oil production	$48,492	$104,249
Well construction and completion	2,100	23,655
Gathering and processing	1,495	2,184
Administration and oversight	455	1,259
Well services	4,432	6,624
Gain on mark-to-market derivatives	46,120	105,585
Other, net	114	33
Total revenues	103,208	243,589
Costs and expenses:		
Gas and oil production	35,842	45,498
Well construction and completion	1,826	20,570
Gathering and processing	2,279	2,417
Well services	2,178	2,198
General and administrative	17,077	17,135
Depreciation, depletion and amortization	30,045	42,991
Total costs and expenses	89,247	130,809
Operating income	13,961	112,780
Interest expense	(27,705)	(25,197)
Gain (loss) on asset sales and disposal	9	(11)
Gain on early extinguishment of debt	26,498	—
Net income	12,763	87,572
Preferred limited partner dividends	(3,648)	(3,653)
Net income attributable to common limited partners and the general partner	$9,115	$83,919
Allocation of net income attributable to common limited partners and the general partner:		
Common limited partners' interest	$8,933	$80,344
General partner's interest	182	3,575
Net income attributable to common limited partners and the general partner	$9,115	$83,919

Net income attributable to common limited partners per unit (Note 2):		
Basic	$0.09	$0.93
Diluted	$0.09	$0.91
Weighted average common limited partner units outstanding (Note 2):		
Basic	102,403	85,529
Diluted	102,696	90,010

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2016	2015
Net income	$12,763	$87,572
Other comprehensive loss:		
Derivative instruments designated as cash flow hedges:		
Reclassification to net income of mark-to-market gains	(3,515)	(27,343)
Total other comprehensive loss	(3,515)	(27,343)
Comprehensive income attributable to common and preferred limited partners and the general partner	$9,248	$60,229

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL (DEFICIT)

(in thousands, except unit data)

(Unaudited)

eral tners' Interest ss A		Preferred Limited Partners' Interest Class C		Class D		Class E		Common Limited Partners' Interests		Class C Common Limited Partner Warrants		A C C
ts	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Amount	I
61,445	$(31,054)	3,749,986	$85,402	4,090,328	$97,518	256,083	$5,819	102,160,866	$(262,864)	562,497	$1,176	$
39	—	—	—	—	—	—	—	245,175	206	—	—	
	—	—	—	—	—	—	—	21,306	(47)	—	—	
	—	—	—	—	—	—	—	—	(3)	—	—	
	(117)	—	(1,913)	—	(2,205)	—	(172)	—	(3,839)	—	—	
	—	—	—	—	—	—	—	—	(11)	—	—	
	182	—	1,275	—	2,201	—	172	—	8,933	—	—	
	—	—	—	—	—	—	—	—	—	—	—	
66,884	$(30,989)	3,749,986	$84,764	4,090,328	$97,514	256,083	$5,819	102,427,347	$(257,625)	562,497	$1,176	$

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Three Months Ended March 31,	
	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$12,763	$87,572
Adjustments to reconcile net income to net cash used in operating activities:		
Depreciation, depletion and amortization	30,045	42,991
Gain on derivatives	(40,332)	(102,382)
(Gain) loss on asset sales and disposal	(9)	11
Gain on extinguishment of debt	(26,498)	—
Non-cash compensation expense	(47)	3,344
Amortization of deferred financing costs and discount and premium on long-term debt	4,101	6,981
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	46,170	42,808
Accounts payable and accrued liabilities	(61,112)	(83,196)
Net cash used in operating activities	(34,919)	(1,871)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(13,170)	(42,498)
Net cash paid for acquisitions	—	(4,602)
Other	—	130
Net cash used in investing activities	(13,170)	(46,970)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under revolving credit facility	135,000	161,000
Repayments under revolving credit facility	(55,000)	(298,000)
Borrowings under second lien term loan facility	—	242,500
Senior note repurchases	(5,528)	—
Distributions paid to unitholders	(8,246)	(49,911)
Net proceeds from issuance of common limited partner units	206	3,327
Arkoma transaction adjustment	—	(8,968)
Deferred financing costs, distribution equivalent rights and other	(411)	(13,772)
Net cash provided by financing activities	66,021	36,176
Net change in cash and cash equivalents	17,932	(12,665)
Cash and cash equivalents, beginning of year	1,353	15,247
Cash and cash equivalents, end of period	$19,285	$2,582

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1 – BASIS OF PRESENTATION

We are a publicly traded (NYSE: ARP) Delaware master-limited partnership (“MLP”) and an independent developer and producer of natural gas, crude oil and natural gas liquids (“NGL”) with operations in basins across the United States. We sponsor and manage tax-advantaged investment partnerships (the “Drilling Partnerships”), in which we coinvest, to finance a portion of our natural gas, crude oil and NGL production activities. Unless the context otherwise requires, references to “Atlas Resource Partners, L.P.,” “Atlas Resource Partners,” “the Partnership,” “we,” “us,” “our” and “our compa refer to Atlas Resource Partners, L.P. and our consolidated subsidiaries.

Atlas Energy Group, LLC (“Atlas Energy Group” or “ATLS”; OTCQX: ATLS), our general partner, manages our operations and activities through its ownership interest. At March 31, 2016, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

In addition to its general and limited partner interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (“AGP”), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

At March 31, 2016, we had 102,427,347 common limited partner units issued and outstanding. The common units are a class of limited partner interests in us. The holders of common units are entitled to participate in partnership distributions, exercise the rights or privileges available to holders of common units and have limited liability as outlined in the partnership agreement.

The accompanying condensed consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2015 was derived from audited financial statements, have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission and are presented in accordance with accounting principles generally accepted in the United States (“U.S. GAAP”) for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. It is suggested that these interim condensed consolidated financial statements be read in conjunction with the financial statements and the notes thereto included in our latest Annual Report on Form 10-K. In management’s opinion, all adjustments necessary for a fair presentation of our financial position, results of operations and cash flows for the periods disclosed have been made. Certain amounts in the prior year’s financial statements have been reclassified to conform to the current year presentation due to the adoption of certain accounting standards (see Notes 2 and 4). The results of operations for the interim periods presented may not necessarily be indicative of the results of operations for the full year.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

Our condensed consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. Transactions between us and other ATLS operations have been identified in the condensed consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

On June 5, 2015, we acquired coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma from ATLS (the "Arkoma Acquisition") for approximately $31.5 million, net of purchase price adjustments. We funded the purchase price through the issuance of 6,500,000 common limited partner units. The Arkoma Acquisition had an effective date of January 1, 2015. We determined that the Arkoma Acquisition constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable Arkoma assets and liabilities based upon their fair values with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit) on our condensed consolidated balance sheets. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the acquired Arkoma assets would have been included in our condensed consolidated financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust our prior period condensed consolidated financial statements to furnish comparative information. As such, we reflected the impact of the Arkoma Acquisition on our condensed consolidated financial statements in the following manner:

- Recognized the assets acquired and liabilities assumed from the Arkoma Acquisition at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital (deficit);
- Retrospectively adjusted the condensed consolidated financial statements for any date prior to June 5, 2015, the date of acquisition, to reflect our results on a consolidated basis with the results of the Arkoma assets as of or at the beginning of the respective period; and
- Adjusted the presentation of our condensed consolidated statements of operations for the three months ended March 31, 2015, to reflect the results of operations attributable to the Arkoma assets prior to the date of acquisition to determine income attributable to common limited partners.

Prior to the Arkoma Acquisition, the common limited partners did not participate in the net income (loss) of the Arkoma operations. Subsequent to the Arkoma Acquisition, the common limited partners participate in the net income (loss) of the Arkoma operations, which was determined after the deduction of the general partner's and the preferred unitholders' interests.

In April 2015, the Financial Accounting Standards Board ("FASB") updated the accounting guidance for earnings per unit ("EPU") of master limited partnerships ("MLP") applying the two-class method. The updated accounting guidance specifies that for general partner transfers (or "drop downs") to an MLP accounted for as a transaction between entities under common control, the earnings (losses) of the transferred business before the date of the transaction should be allocated entirely to the general partner's interest, and previously reported EPU of the limited partners should not change. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the drop down transaction occurs are also required. We adopted this accounting guidance upon its effective date of January 1, 2016, which resulted in the following retrospective restatement:

Condensed Consolidated Statement of Operations	Previously Filed	Adjustment	Restated
Three Months Ended March 31, 2015:			
Common limited partners' interest	$82,240	$ (1,896)	$80,344
General partner's interest	$1,679	$ 1,896	$3,575
Net loss attributable to common limited partners per unit - basic	$0.95	$ (0.02)	$0.93
Net loss attributable to common limited partners per unit - diluted	$0.93	$ (0.02)	$0.91
Condensed Consolidated Balance Sheet			
December 31, 2015:			
Common limited partners' interest	$(260,276)	$ (2,588)	$(262,864)
General partners' interest	$(33,642)	$ 2,588	$(31,054)

In accordance with established practice in the oil and gas industry, our condensed consolidated financial statements include our pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the Drilling Partnerships in which we have an interest. Such interests generally approximate 30%. Our condensed consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, we calculate these items specific to our own economics.

Use of Estimates

The preparation of our condensed consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our condensed consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. Our condensed consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization and fair value of derivative instruments. The oil and gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Actual results could differ from those estimates.

Liquidity and Capital Resources

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline and remain low in 2016. These lower commodity prices have negatively impacted our revenues, earnings and cash flows. Sustained low commodity prices will have a material and adverse effect on our liquidity position.

On May 10, 2016, we entered into a ninth amendment (the "Ninth Amendment") to our Second Amended and Restated Credit Agreement, dated July 31, 2013 (as amended from time to time, the "Credit Agreement"), with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, to, among other things, waive the requirement that our ratio of current assets to current liabilities (as calculated pursuant to the Credit Agreement) not be less than 1.0 to 1.0 as of March 31, 2016 and waive the requirement that our ratio of the total First Lien Debt to EBITDA (as calculated pursuant to the Credit Agreement) not be greater than 2.75 to 1.0 as of March 31, 2016, and required us to repay $2.5 million of outstanding borrowings. We are party to a Second Lien Credit Agreement, dated February 23, 2015, with certain lenders and Wilmington Trust, National Association, as administrative agent (the "Term Loan Facility"), which contains the same financial covenants as those in our Credit Agreement. Such financial covenants were automatically waived as a result of the Ninth Amendment to the Credit Agreement. Based on the terms of the Ninth Amendment to the Credit Agreement and uncertainty regarding future covenant compliance, we classified $672.0 million of our outstanding amounts under the Credit Agreement and $234.2 million of our outstanding amounts under the Term Loan Facility, net of $10.0 million deferred financing costs and $5.8 million unamortized discount, as current portion of long-term debt within our condensed consolidated balance sheet as of March 31, 2016.

Our borrowing base, and thus our borrowing capacity, under the Credit Agreement is impacted by the level of our oil and natural gas reserves. Downward revisions of our oil and natural gas reserves volume and value due to low commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant. Our Credit Agreement is currently in the process of its semi-annual redetermination. Based on projected market conditions, continued declines in commodity prices and recent conversations with our administrative agent, we expect that our borrowing base will be redetermined to a level below our outstanding borrowings of $672.0 million under the Credit Agreement as of March 31, 2016. In the case of a borrowing base deficiency, our Credit Agreement requires us to repay the deficiency, which we are permitted to do in equal monthly installments over a four-month period, or deposit additional collateral to eliminate such deficiency. If our borrowing base is redetermined below our current outstanding borrowings and we are unable to repay the deficiency or deposit additional collateral to eliminate such deficiency, there would be substantial doubt regarding our ability to continue as a going concern.

In addition, if we are unable to remain in compliance with the covenants under our credit facilities or the indentures governing our Senior Notes (as defined in Note 4), absent relief from our lenders or noteholders, as applicable, we may be forced to repay or refinance such indebtedness. Upon the occurrence of an event of default, the lenders under our credit facilities or holders or our notes, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit. If an event of default occurs (including if our borrowing base is redetermined below our current outstanding borrowings and we are unable to repay the deficiency or deposit additional collateral to eliminate such deficiency), or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we will not have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there would be substantial doubt regarding our ability to continue as a going concern.

We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity, strengthening our balance sheet, meeting our debt service obligations and/or achieving cost efficiency. Although we have a significant hedge position for the remainder of 2016 through 2018, the forecasted long-term downturn in commodity prices has had a detrimental impact on our financial position. For example, we could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options with the lenders under our Credit Agreement and Term Loan Facility, and holders of our Senior Notes, but there is no certainty that we will be able to implement any such options, and we cannot provide any assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders, including cancellation of debt income ("CODI") which would be directly allocated to our unitholders and reported on such unitholders' separate returns (see Item 1A – Risk Factors for additional information).

We also continue to implement various cost saving measures to reduce our capital, operating and general and administrative costs, including renegotiating contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs. We will continue to be opportunistic and aggressive in managing our cost structure and, in turn, our liquidity to meet our capital and operating needs. We cannot provide any assurances that any of these efforts will be successful or will result in cost reductions or cash flows or the timing of any such cost reductions or additional cash flows. It is also possible additional adjustments to our plan and outlook may occur based on market conditions and our needs at that time, which could include selling assets, liquidating all or a portion of our hedge portfolio, seeking additional partners to develop our assets, reducing or suspending the payments of distributions to preferred unitholders and/or reducing our planned capital program. In addition, to the extent commodity prices remain low or decline further, or we experience disruptions in our longer-term access to or cost of capital, our ability to fund future capital expenditures or growth projects may be further impacted.

Net Income Per Common Unit

Basic net income attributable to common limited partners per unit is computed by dividing net income attributable to common limited partners, which is determined after the deduction of the general partner's and the preferred unitholders' interests, by the weighted average number of common limited partner units outstanding during the period. Net income attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, income attributable to preferred limited partners and net income attributable to the general partner's Class A units. The general partner's interest in net income is calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 10), with a priority allocation of net income to the general partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income allocated with respect to the general partner's and limited partners' ownership interests.

We present net income per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights' share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, our management believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Unvested unit-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. Phantom unit awards, which consist of common units issuable under the terms of our long-term incentive plan, contain non-forfeitable rights to distribution equivalents. The participation rights would result in a non-contingent transfer of value each time we declare a distribution or distribution equivalent right during the award's vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. As such, the net income utilized in the calculation of net income per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net income allocated to the common limited partners for purposes of calculating net income attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended March 31,	
	2016	2015
Net income	$ 12,763	$ 87,572
Preferred limited partner dividends	(3,648)	(3,653)
Net income attributable to common limited partners and the general partner	9,115	83,919
Less: General partner's interest	182	3,575
Net income attributable to common limited partners	8,933	80,344
Less: Net income attributable to participating securities – phantom units	25	644
Net income utilized in the calculation of net income attributable to common limited partners per unit - Basic	8,908	79,700
Plus: Convertible preferred limited partner dividends[(1)]	—	1,928
Net income utilized in the calculation of net income attributable to common limited partners per unit - Diluted	$ 8,908	$ 81,628

(1) For the three months ended March 31, 2016, distributions on our Class C convertible preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

Diluted net income attributable to common limited partners per unit is calculated by dividing net income attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, convertible preferred units and warrants, as calculated by the treasury stock or if converted methods, as applicable. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of our long-term incentive plan.

The following table sets forth the reconciliation of our weighted average number of common limited partner units used to compute basic net income attributable to common limited partners per unit with those used to compute diluted net income attributable to common limited partners per unit (in thousands):

	Three Months Ended March 31,	
	2016	2015
Weighted average number of common limited partner units—basic	102,403	85,529
Add effect of dilutive incentive awards	293	691
Add effect of dilutive convertible preferred limited partner units[(1)]	—	3,790
Weighted average number of common limited partner units—diluted	102,696	90,010

(1) For the three months ended March 31, 2016, potential common limited partner units issuable upon (a) conversion of our Class C preferred units and (b) exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As the Class D and Class E preferred units are

convertible only upon a change of control event, they are not considered dilutive securities for earnings per unit purposes.

Recently Issued Accounting Standards

In February 2016, the FASB updated the accounting guidance related to leases. The updated accounting guidance requires lessees to recognize a lease asset and liability at the commencement date of all leases (with the exception of short-term leases), initially measured at the present value of the lease payments. The updated guidance is effective for us as of January 1, 2019 and requires a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest period presented. We are currently in the process of determining the impact that the updated accounting guidance will have on our condensed consolidated financial statements.

In August 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs specific to line of credit arrangements. The updated accounting guidance allows the option of presenting deferred debt issuance costs related to line-of-credit arrangements as an asset, and subsequently amortizing over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. We adopted the updated accounting guidance effective January 1, 2016, and it did not have a material impact on our condensed consolidated financial statements.

In February 2015, the FASB updated the accounting guidance related to consolidation under the variable interest entity and voting interest entity models. The updated accounting guidance modifies the consolidation guidance for variable interest entities, limited partnerships and similar legal entities. We adopted this accounting guidance upon its effective date of January 1, 2016, and it did not have a material impact on our condensed consolidated financial statements.

In August 2014, the FASB updated the accounting guidance related to the evaluation of whether there is substantial doubt about an entity's ability to continue as a going concern. The updated accounting guidance requires an entity's management to evaluate whether there are conditions or events that raise substantial doubt about its ability to continue as a going concern within one year from the date the financial statements are issued and provide footnote disclosures, if necessary. We adopted this accounting guidance on January 1, 2016, and provided enhanced disclosures, as applicable, within our condensed consolidated financial statements.

In May 2014, the FASB updated the accounting guidance related to revenue recognition. The updated accounting guidance provides a single, contract-based revenue recognition model to help improve financial reporting by providing clearer guidance on when an entity should recognize revenue, and by reducing the number of standards to which an entity has to refer. In July 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The updated accounting guidance provides companies with alternative methods of adoption. We are currently in the process of determining the impact that the updated accounting guidance will have on our condensed consolidated financial statements and our method of adoption.

NOTE 3 – PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment at the dates indicated (in thousands):

	March 31, 2016	December 31, 2015	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$504,958	$503,586	
Pre-development costs	6,401	6,014	
Wells and related equipment	3,085,097	3,076,239	
Total proved properties	3,596,456	3,585,839	
Unproved properties	213,047	213,047	
Support equipment	45,136	44,921	

Total natural gas and oil properties	3,854,639	3,843,807	
Pipelines, processing and compression facilities	57,591	56,738	15 – 20
Rights of way	829	829	20 – 40
Land, buildings and improvements	9,798	9,798	3 – 40
Other	18,420	18,405	3 – 10
	3,941,277	3,929,577	
Less – accumulated depreciation, depletion and amortization	(2,766,232)	(2,737,966)	
	$1,175,045	$1,191,611	

During the three months ended March 31, 2016 and 2015, we recognized $18.7 million and $21.5 million, respectively, of non-cash property, plant and equipment additions, which were included within the changes in accounts payable and accrued liabilities on our condensed consolidated statements of cash flows.

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds by us was 6.7% and 6.1% for the three months ended March 31, 2016 and 2015, respectively. The aggregate amount of interest capitalized by us was $2.4 million and $3.9 million for the three months ended March 31, 2016 and 2015, respectively.

For the three months ended March 31, 2016 and 2015, we recorded $1.7 million and $1.6 million, respectively, of accretion expense related to our asset retirement obligations within depreciation, depletion and amortization in our condensed consolidated statements of operations. For the three months ended March 31, 2016 and 2015, we incurred liabilities of $2.8 million and $0.2 million, respectively, in asset retirement obligations in our condensed consolidated balance sheet due to the liquidation of some of our Drilling Partnerships.

NOTE 4 - DEBT

Total debt consists of the following at the dates indicated (in thousands):

	March 31, 2016	December 31, 2015
Revolving credit facility	$672,000	$592,000
Term loan facility	244,159	243,783
7.75 % Senior Notes – due 2021	354,366	374,619
9.25 % Senior Notes – due 2021	312,055	324,080
Deferred financing costs	(28,820)	(31,055)
Total debt, net	1,553,760	1,503,427
Less current maturities	(906,156)	—
Total long-term debt, net	$647,604	$1,503,427

In April 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs. The updated accounting guidance requires that debt issuance costs be presented as a direct deduction from the associated debt obligation. We adopted this accounting guidance upon its effective date of January 1, 2016. The retrospective effect of the reclassification resulted in the following changes:

Condensed Consolidated Balance Sheet	Previously Filed	Adjustment	Restated
December 31, 2015:			
Other assets, net	$60,044	$ (31,055)	$28,989
Long-term debt, net	$1,534,482	$ (31,055)	$1,503,427

Cash Interest. Total cash payments for interest by us were $41.2 million and $36.7 million for the three months ended March 31, 2016 and 2015, respectively.

Credit Facility

We are a party to a Credit Agreement with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which provides for a senior secured revolving credit facility with a borrowing base of $700.0 million as of March 31, 2016 and a maximum facility amount of $1.5 billion scheduled to mature in July 2018. At March 31, 2016, $672.0 million was outstanding under the credit facility.

Our borrowing base is scheduled for semi-annual redeterminations in May and November of each year. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.2 million was outstanding at March 31, 2016. Our obligations under the facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets. Additionally, obligations under the facility are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor. At March 31, 2016, the weighted average interest rate on outstanding borrowings under the credit facility was 3.6%.

The Credit Agreement contains customary covenants including, without limitation, covenants that limit our ability to incur additional indebtedness (but which permits second lien debt in an aggregate principal amount of up to $300.0 million and third lien debt that satisfies certain conditions including pro forma financial covenants), grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidate with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. The Credit Agreement also requires us to maintain a ratio of First Lien Debt to EBITDA (ratio as defined in the Credit Agreement) of not greater than 2.75 to 1.00, and a ratio of current assets to current liabilities (ratio as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

On May 10, 2016, we entered into the Ninth Amendment to the Credit Agreement, to, among other things, waive the requirement that our ratio of current assets to current liabilities (as calculated pursuant to the Credit Agreement) not be less than 1.0 to 1.0 as of March 31, 2016 and waive the requirement that our ratio of the total First Lien Debt to EBITDA (as calculated pursuant to the Credit Agreement) not be greater than 2.75 to 1.0 as of March 31, 2016, and required us to repay $2.5 million of outstanding borrowings. As a result of the Ninth Amendment to the Credit Agreement and uncertainty regarding future covenant compliance, we classified $672.0 million of our outstanding amounts under the Credit Agreement as current portion of long-term debt within our condensed consolidated balance sheet as of March 31, 2016. See Note 2 for additional disclosure regarding our liquidity and capital resources.

Our Credit Agreement is currently in the process of its semi-annual redetermination. Based on projected market conditions, continued declines in commodity prices and recent conversations with our administrative agent, we expect that our borrowing base will be redetermined to a level below our outstanding borrowings under the Credit Agreement as of March 31, 2016. In the case of a borrowing base deficiency, our Credit Agreement requires us to repay the deficiency, which we are permitted to do in equal monthly installments over a four-month period, or deposit additional collateral to eliminate such deficiency. See Note 2 for additional disclosure regarding our liquidity and capital resources.

Term Loan Facility

We are party to a Term Loan Facility, which provides for a second lien term loan in an original principal amount of $250.0 million. The Term Loan Facility matures on February 23, 2020. The Term Loan Facility is presented in the table above net of unamortized discount of $5.8 million at March 31, 2016.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. At March 31, 2016, the weighted average interest rate on outstanding borrowings under the Term Loan Facility was 10.0%.

The Term Loan Facility contains customary covenants including, without limitation, covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Term Loan Facility contains covenants substantially similar to those in the Credit Agreement, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. The financial covenants of the Term Loan Facility were automatically waived as a result of the Ninth Amendment to the Credit Agreement. Based on the terms of the Ninth Amendment to the Credit Agreement and uncertainty regarding future covenant compliance, we classified $234.2 million of our amounts outstanding on the Term Loan Facility, net of $10.0 million deferred financing costs and $5.8 million unamortized discount, as current portion of long-term debt within our condensed consolidated balance sheet as of March 31, 2016. See Note 2 for additional disclosure regarding our liquidity and capital resources.

Senior Notes

At March 31, 2016, we had $354.4 million outstanding of our 7.75% senior unsecured notes due 2021 (“7.75% Senior Notes”). The 7.75% Senior Notes were presented net of a $0.4 million unamortized discount as of March 31, 2016.

At March 31, 2016, we had $312.1 million outstanding of our 9.25% senior unsecured notes due 2021 (“9.25% Senior Notes”). The 9.25% Senior Notes were presented net of a $0.9 million unamortized discount as of March 31, 2016.

In January and February 2016, we executed transactions to repurchase portions of our senior unsecured notes. As of March 31, 2016, we repurchased approximately $20.3 million of our 7.75% Senior Notes due 2021 and approximately $12.1 million of our 9.25% Senior Notes for approximately $5.5 million, which includes $0.6 million of interest. As a result of these transactions, we recognized $26.5 million as gain on early extinguishment of debt, net of accelerated amortization of deferred financing costs of $0.9 million, for the three months ended March 31, 2016.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several, subject to certain customary automatic release provisions, including, in certain circumstances, the sale or other disposition of all or substantially all the assets of, or all of the equity interests in, the subsidiary guarantor, or the subsidiary guarantor is declared “unrestricted” for covenant purposes, and any subsidiaries of ours, other than the subsidiary guarantors, are minor. There are no restrictions on our ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants including, without limitation, covenants that limit our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We were in compliance with these covenants as of March 31, 2016.

NOTE 5 – DERIVATIVE INSTRUMENTS

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price risk management activities. We do not apply hedge accounting to any of our derivative instruments. As a result, gains and losses associated with derivative instruments are recognized in earnings.

We enter into commodity future option contracts to achieve more predictable cash flows by hedging our exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile Stock Exchange (“NYMEX”) futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the physical delivery of the commodity. Crude oil contracts are based on a West Texas Intermediate (“WTI”) index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts were recorded at their fair values.

We recorded net derivative assets of $354.8 million and $357.7 million on our condensed consolidated balance sheets at March 31, 2016 and December 31, 2015, respectively. Of the $15.9 million of deferred gains in accumulated other comprehensive income on our condensed consolidated balance sheet at March 31, 2016, we expect to reclassify $12.1 million of gains to our condensed consolidated statement of operations over the next twelve month period as these contracts expire with the remaining gains of $3.8 million being reclassified to our condensed consolidated statements of operations in later periods as the remaining contracts expire.

The following table summarizes the commodity derivative activity and presentation in our condensed consolidated statements of operations for the periods indicated (in thousands):

Thre

	Three Months Ended March 31,	
	2016	2015
Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets(1)	$3,515	$27,343
Portion of settlements attributable to subsequent mark to market gains	45,193	15,203
Total cash settlements on commodity derivative contracts	$48,708	$42,546
Gains recognized on cash settlement(2)	$5,788	$3,203
Gains recognized on open derivative contracts(2)	40,332	102,382
Gains on mark-to-market derivatives	$46,120	$105,585

(1) Recognized in gas and oil production revenue.
(2) Recognized in gain on mark-to-market derivatives.

The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities included on our condensed consolidated balance sheets for the periods indicated (in thousands):

Offsetting Derivatives as of March 31, 2016	Gross Amounts Recognized	Gross Amounts Offset	Net Amount Presented
Current portion of derivative assets	$ 159,745	$ —	$ 159,745
Long-term portion of derivative assets	195,074	—	195,074
Total derivative assets	$ 354,819	$ —	$ 354,819
Current portion of derivative liabilities	$ —	$ —	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ —	$ —	$ —
Offsetting Derivatives as of December 31, 2015			
Current portion of derivative assets	$ 159,460	$ —	$ 159,460
Long-term portion of derivative assets	198,262	—	198,262
Total derivative assets	$ 357,722	$ —	$ 357,722
Current portion of derivative liabilities	$ —	$ —	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ —	$ —	$ —

At March 31, 2016, we had the following commodity derivatives:

Type	Production Period Ending December 31,	Volumes[1]	Average Fixed Price[1]	Fair Value Asset (in thousands)[2]	Total Type (in thousands)[2]
Natural Gas – Fixed Price Swaps	2016[3]	40,354,500	$ 4.226	$ 80,594	
	2017	50,120,000	$ 4.221	$ 72,296	
	2018	40,300,000	$ 4.168	$ 51,782	
	2019	15,860,000	$ 4.019	$ 16,932	
					$ 221,604
Natural Gas – Put Options – Drilling Partnerships	2016[3]	1,080,000	$ 4.150	$ 2,078	
					$ 2,078
Crude Oil – Fixed Price Swaps	2016[3]	1,230,800	$ 81.685	$ 49,864	
	2017	1,200,000	$ 77.610	$ 39,372	
	2018	1,080,000	$ 76.281	$ 31,413	
	2019	540,000	$ 68.371	$ 10,488	

	$ 131,137
Total net assets	$ 354,819

(1) Volumes for natural gas are stated in million British Thermal Units. Volumes for NGLs are stated in gallons. Volumes for crude oil are stated in barrels.
(2) Fair value for natural gas fixed price swaps and natural gas put options are based on forward NYMEX natural gas prices, as applicable. Fair value of crude oil fixed price swaps are based on forward WTI crude oil prices, as applicable.
(3) The production volumes for 2016 include the remaining nine months of 2016 beginning April 1, 2016.

NOTE 6 – FAIR VALUE OF FINANCIAL INSTRUMENTS

We use a market approach fair value methodology to value our outstanding derivative contracts. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into the three level hierarchy (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of March 31, 2016 and December 31, 2015, all of our derivative financial instruments were classified as Level 2.

Information for financial instruments measured at fair value at March 31, 2016 and December 31, 2015 was as follows (in thousands):

As of March 31, 2016	Level 1	Level 2	Level 3	Total
Derivative assets				
Commodity swaps	$ —	$352,741	$ —	$352,741
Commodity puts	—	2,078	—	2,078
Total derivatives, fair value	$ —	$354,819	$ —	$354,819

As of December 31, 2015	Level 1	Level 2	Level 3	Total
Derivative assets				
Commodity swaps	$ —	$355,329	$ —	$355,329
Commodity puts	—	2,393	—	2,393
Total derivatives, fair value	$ —	$357,722	$ —	$357,722

Other Financial Instruments

Our other current assets and liabilities on our condensed consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair values of our long-term debt at March 31, 2016 and December 31, 2015, which consist of our Senior Notes and outstanding borrowings under our revolving credit and term loan facility (see Note 4), were $1,026.0 million and $907.8 million, respectively, compared with the carrying amounts of $1,553.8 million and $1,503.4 million, respectively. At March 31, 2016 and December 31, 2015, the carrying values of outstanding borrowings under our revolving credit facility (see Note 4), which bears interest at variable interest rates, approximated estimated fair value. The estimated fair values of our Senior Notes and the term loan facility were based upon the market approach and calculated using yields of our Senior Notes and the term loan credit facility as provided by financial institutions and thus were categorized as Level 3 values.

NOTE 7 — CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with ATLS. We do not directly employ any persons to manage or operate our business. These functions are provided by employees of ATLS and/or its affiliates. As of March 31, 2016 and December 31, 2015, we had a

$7.2 million receivable and a $1.3 million payable, respectively, to/from ATLS related to the timing of funding cash accounts related to general and administrative expenses, such as payroll and benefits, which was recorded in advances to/from affiliates in the condensed consolidated balance sheets.

Relationship with Drilling Partnerships. We conduct certain activities through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. We serve as general partner and operator of the Drilling Partnerships and assume customary rights and obligations for the Drilling Partnerships. As the general partner, we are liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the Drilling if we breach our responsibilities with respect to the operations of the Drilling Partnerships. We are entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership's revenue and costs and expenses according to the respective partnership agreements. In March 2016, we transferred $36.7 million of investor capital raised and $13.3 million of accrued well drilling and completion costs incurred to the Atlas Eagle Ford 2015 L.P. private drilling partnership for activities directly related to their program. We intend to continue to fund the Drilling Partnerships' operations and obligations, as necessary, until they are liquidated. Depending on commodity pricing and each of the Drilling Partnerships' reserves value, we expect to realize all outstanding receivables from the Drilling Partnerships' through the receipt of cash flows from their operations and/or the transfer of net assets and liabilities to us upon their liquidation. As of March 31, 2016 and December 31, 2015, we had receivables of $7.9 million and a $6.6 million, respectively, from certain of the Drilling Partnerships', which was recorded in accounts receivable in the condensed consolidated balance sheets. As of March 31, 2016 and December 31, 2015, we had payables of $3.9 million and $3.0 million, respectively, to certain of the Drilling Partnerships', which was recorded in accounts payable in the condensed consolidated balance sheets.

Relationship with AGP. At the direction of ATLS, we allocate indirect costs, such as rent and other general and administrative costs, to AGP based on the number of ATLS employees who devoted time to AGP's activities. In addition, Anthem Securities, Inc. ("Anthem"), a wholly owned subsidiary of us, acted as dealer manager for AGP's private placement offering, which was completed in June 2015. As the dealer manager, Anthem received compensation from AGP equal to a maximum of 12% of the gross proceeds of the private placement offering as selling commissions, marketing efforts, and other issuance costs. Anthem is currently acting as the dealer manager for AGP's issuance and sale in a continuous offering of up to a maximum agreement amount of 100,000,000 common units representing limited partner interests in AGP as further described in AGP's registration statement on Form S-1 (File No. 333-207537). AGP will pay Anthem (1) compensation equal to 3.00% of the gross proceeds of the offering (Anthem may reallow up to 1.50% of gross offering proceeds it receives as dealer manager fees to participating broker-dealers, but expects to reallow 1.25% of gross offering proceeds to participating broker-dealers); (2) 7.00% and 3.00% of aggregate gross proceeds from the sale of Class A common units and Class T common units, respectively, as sales commissions; (3) with respect to Class T common units, a distribution and unitholder servicing fee in the aggregate amount of 4.00% of the gross proceeds from the sale of Class T common units, which distribution and unitholder servicing fee will be withheld from cash distributions otherwise payable to the purchasers of Class T common units at a rate of $0.025 per quarter per unit. As of March 31, 2016 and December 31, 2015, we had a $3.8 million receivable and $8.7 million payable, respectively, to/from AGP related to AGP's indirect cost allocation and dealer manager costs, which was recorded in advances to/from affiliates in the condensed consolidated balance sheets.

NOTE 8 — COMMITMENTS AND CONTINGENCIES

General Commitments

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of March 31, 2016, our management believes that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

While our historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized. For the three months ended March 31, 2016 and 2015, $0.1 million and $0.5 million, respectively, of our gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses.

As of March 31, 2016, we are committed to expend approximately $5.5 million, principally on drilling and completion expenditures.

Legal Proceedings

We are party to various routine legal proceedings arising out of the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations.

NOTE 9 –ISSUANCES OF UNITS

We have an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to $100.0 million. Sales of common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent. During the three months ended March 31, 2016, we issued 245,175 common limited partner units under the equity distribution program for net proceeds of $0.2 million, net of approximately $19,000 in commissions and offering expenses paid. During the three months ended March 31, 2015, we issued 420,586 common limited partner units under the equity distribution program for net proceeds of $3.3 million, net of $0.1 million in commissions and offering expenses paid.

In August 2015, we entered into a distribution agreement with MLV & Co. LLC, which we terminated and replaced in November 2015, when we entered into a distribution agreement with MLV and FBR Capital Markets & Co. in which we may sell our 8.625% Class D Cumulative Redeemable Perpetual Preferred Units ("Class D Preferred Units") and Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units"). Under both the August 2015 ATM Agreement and the November 2015 ATM Agreement, we did not issue any Class D Preferred units nor Class E Preferred Units under the preferred equity distribution program for the three months ended March 31, 2016 and 2015.

On March 31, 2015, to partially pay our portion of a quarterly installment related to the Eagle Ford acquisition, we issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit.

On January 12, 2016, we were notified by the NYSE that we were not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of our common units had been less than $1.00 for 30 consecutive trading days. We are working to remedy this situation in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE.

NOTE 10 – CASH DISTRIBUTIONS

We have a monthly cash distribution program whereby we distribute all of our available cash (as defined in the partnership agreement) for that month to our unitholders within 45 days from the month end. If our common unit distributions in any quarter exceed specified target levels, ATLS will receive between 13% and 48% of such distributions in excess of the specified target levels. While outstanding, our Class B Preferred Units received regular quarterly cash distributions equal to the greater of (i) $0.40 (or $0.1333 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. Until the Board's decision in May 2016 (as discussed below), while outstanding, our Class C Preferred Units receive regular quarterly cash distributions equal to the greater of (i) $0.51 (or $0.17 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. We pay quarterly distributions on our Class D Preferred Units at an annual rate of $2.15625 per unit, $0.5390625 per unit paid on a quarterly basis, or 8.625% of the $25.00 liquidation preference. We pay quarterly distributions on our Class E Preferred Units at an annual rate of $2.6875 per unit, or $0.671875 per unit on a quarterly basis, or 10.75% of the $25.00 liquidation preference. On May 5, 2016, the Board of Directors elected to suspend our common unit and Class C preferred distributions, beginning with the month of March of 2016, due to the continued lower commodity price environment.

During the three months ended March 31, 2016, we paid three monthly cash distributions totaling approximately $3.8 million to common limited partners ($0.0125 per unit per month); $1.9 million to Preferred Class C limited partners ($0.17 per unit per month); and $0.1 million to the General Partner Class A holder ($0.0125 per unit per month). During the three months ended March 31, 2015, we paid three monthly cash distributions totaling approximately $42.8 million to common limited partners ($0.1966 per unit for both January and February 2015 and $0.1083 per unit for March 2015); $2.1 million to Preferred Class C limited partners ($0.1966 per unit for both January and February 2015 and $0.17 per unit for March 2015); and $3.0 million to the General Partner Class A holder ($0.1966 per unit for both January and February 2015 and $0.1083 per unit for March 2015).

During the three months ended March 31, 2016, we paid a distribution of $2.2 million to Class D Preferred limited partners ($0.5390625 per unit) for the period October 15, 2015 through January 14, 2016. During the three months ended March 31, 2015, we paid a distribution of $2.0 million to Class D Preferred limited partners ($0.6169270 per unit) for the period October 2, 2014 through January 14, 2015.

During the three months ended March 31, 2016, we paid a distribution of $0.2 million to Class E Preferred limited partners ($0.671875 per unit) for the period October 15, 2015 through January 14, 2016. No distributions were paid to Class E Preferred limited partners during the three months ended March 31, 2015.

NOTE 11 – OPERATING SEGMENT INFORMATION

Our operations include three reportable operating segments. These operating segments reflect the way we manage our operations and make business decisions. Operating segment data for the periods indicated were as follows (in thousands):

	Three Months Ended March 31,	
	2016	2015
Gas and oil production: (3)		
Revenues	$94,612	$209,834
Operating costs and expenses	(35,842)	(45,498)
Depreciation, depletion and amortization expense	(26,580)	(40,118)
Segment income	$32,190	$124,218
Well construction and completion:		
Revenues	$2,100	$23,655
Operating costs and expenses	(1,826)	(20,570)
Segment income	$274	$3,085
Other partnership management:(1)		
Revenues	$6,496	$10,100
Operating costs and expenses	(4,457)	(4,615)
Depreciation, depletion and amortization expense	(3,465)	(2,873)
Segment income (loss)	$(1,426)	$2,612
Reconciliation of segment income (loss) to net income:		
Segment income (loss):		
Gas and oil production	$32,190	$124,218
Well construction and completion	274	3,085
Other partnership management	(1,426)	2,612
Total segment income	31,038	129,915
General and administrative expenses(2)	(17,077)	(17,135)
Interest expense(2)	(27,705)	(25,197)
Gain on early extinguishment of debt(2)	26,498	—
Gain (loss) on asset sales and disposal(2)	9	(11)
Net income	$12,763	$87,572
Reconciliation of segment revenues to total revenues:		
Gas and oil production(3)	$94,612	$209,834
Well construction and completion	2,100	23,655
Other partnership management	6,496	10,100

Total revenues	$103,208	$243,589
Capital expenditures:		
Gas and oil production	$11,945	$32,192
Other partnership management	1,134	10,094
Corporate and other	91	212
Total capital expenditures	$13,170	$42,498

(1) Includes revenues and expenses from well services, gathering and processing, administration and oversight, and other, net that do not meet the quantitative threshold for reporting segment information.

(2) Gain (loss) on asset sales and disposal, general and administrative expenses, gain on early extinguishment of debt and interest expense have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented.

(3) Gas and oil production segment revenues include gains on mark to market derivatives.

	March 31, 2016	December 31, 2015
Balance sheet:		
Goodwill:		
Well construction and completion	$6,389	$6,389
Other partnership management	7,250	7,250
Total goodwill	$13,639	$13,639
Total assets:		
Gas and oil production	$1,524,980	$1,551,450
Well construction and completion	7,170	27,039
Other partnership management	64,067	66,641
Corporate and other	83,280	54,819
Total assets	$1,679,497	$1,699,949

NOTE 12 – SUBSEQUENT EVENTS

Cash Distributions. On April 15, 2016, we paid a quarterly distribution of $2.2 million to Class D Preferred limited partners ($0.5390625 per unit) for the period January 15, 2016 through April 14, 2016.

On April 15, 2016, we paid a quarterly distribution of $0.2 million to Class E Preferred limited partners ($0.671875 per unit) for the period January 15, 2016 through April 14, 2016.

On May 5, 2016, the Board of Directors elected to suspend our common unit and Class C preferred distributions, beginning with the month of March of 2016, due to the continued lower commodity price environment.

Ninth Amendment to the Credit Agreement. On May 10, 2016, we entered into the Ninth Amendment to the Credit Agreement (see Note 4).

Long-Term Incentive Plan Vesting Delay. On May 12, 2016, due to the income tax ramifications of the potential options we are currently considering, the Board of Directors of our General Partner delayed the vesting date of approximately 110,000 units granted to employees and officers in until March 2017. The phantom units, which were set to vest on May 15, 2016, were originally granted in May 2012.

ITEM 2: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements

When used in this Form 10-Q, the words "believes," "anticipates," "expects" and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in "Item 1A. Risk Factors" in our annual report on Form 10-K for the year ended December 31, 2015. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements, which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

BUSINESS OVERVIEW

We are a publicly-traded (NYSE: ARP) Delaware master-limited partnership ("MLP") and an independent developer and producer of natural gas, crude oil and natural gas liquids ("NGL"), with operations in basins across the United States. We sponsor and manage tax-advantaged investment partnerships ("Drilling Partnerships"), in which we coinvest, to finance a portion of our natural gas, crude oil and natural gas liquid production activities.

Atlas Energy Group, LLC ("Atlas Energy Group" or "ATLS"; OTCQX: ATLS), our general partner, manages our operations and activities through its ownership interest. At March 31, 2016, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

In addition to its general and limited partner interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. ("AGP"), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

FINANCIAL PRESENTATION

Our consolidated balance sheets at March 31, 2016 and December 31, 2015, and the consolidated statements of operations for the three months ended March 31, 2016 and 2015 include our accounts and our wholly-owned subsidiaries. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the consolidation of the financial statements.

RECENT DEVELOPMENTS

- Revolving credit facility amendment. On May 10, 2016, we entered into an amendment to our revolving credit agreement to waive the requirement of certain of our financial covenant ratios as of March 31, 2016. See our Liquidity and Capital Resources section for further details.
- Senior Note Repurchases. In January and February 2016, we executed transactions to repurchase approximately $20.3 million of our unsecured 7.75% Senior Notes in 2021 and approximately $12.1 million of our unsecured

9.25% Senior Notes for approximately $5.5 million. As a result of these transactions, we recognized approximately $26.5 million as gain on early extinguishment of debt in the first quarter of 2016. (See Item 1: "Financial Statements (Unaudited)" – Note 4 for further details).

- NYSE Compliance. On January 12, 2016, we were notified by the NYSE that we were not in compliance with NYSE's continued listing criteria under Section 802.01C of the NYSE Listed Company Manual because the average closing price of the common units had been less than $1.00 for 30 consecutive trading days. We are working to remedy this situation in a timely manner as set forth in the applicable NYSE rules in order to maintain our listing on the NYSE.

GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by key trends in natural gas and oil production markets. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

The natural gas, oil and natural gas liquids commodity price markets have suffered significant declines since the fourth quarter of 2014 through the first quarter of 2016. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, our ability to make payments on our debt and our ability to make distributions to our unitholders, including ATLS, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas and oil production from particular wells decrease. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. To the extent we do not have sufficient capital, our ability to drill and acquire more reserves will be negatively impacted.

RESULTS OF OPERATIONS

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various plays throughout the United States. Through March 31, 2016, we have established production positions in the following operating areas:

- South Texas - the Eagle Ford Shale, in which we and AGP acquired acreage and producing wells in November 2014;
- coal-bed methane producing natural gas assets in (1) the Raton Basin in northern New Mexico and the Black Warrior Basin in central Alabama, acquired in 2013; (2) the Central Appalachia Basin in West Virginia and Virginia, acquired in 2014, and; (3) the Arkoma Basin in eastern Oklahoma, acquired in 2015.
- the Rangely field in northwest Colorado, a mature tertiary CO_2 flood with low-decline oil production, where we have a 25% non-operated net working interest position which we acquired on June 30, 2014;
- the Appalachia Basin assets, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region; the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; and the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile;
- North Texas - the Barnett Shale and Marble Falls play, both in the Fort Worth Basin. The Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil.
- the Mid-Continent assets, including Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area, and the Niobrara Shale assets in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled and the number of wells we turned in line, both gross and for our interest, during the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31, 2016	2015
Gross wells drilled:		
Barnett/Marble Falls	—	3
Mississippi Lime	—	2
Total	—	5
Net wells drilled[(1)]:		
Barnett/Marble Falls	—	2
Mississippi Lime	—	1
Total	—	3
Gross wells turned in line[(2)(3)]:		
Barnett/Marble Falls	—	14
Eagle Ford	—	2
Mississippi Lime	—	5
Total	—	21
Net wells turned in line[(1)(2)(3)]:		
Barnett/Marble Falls	—	4
Eagle Ford	—	1
Mississippi Lime	—	2
Total	—	7

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in our Drilling Partnerships.
(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.
(3) There were no exploratory wells drilled during the three months ended March 31, 2016 and 2015; there were no gross or net dry wells within our operating areas during the three months ended March 31, 2016 and 2015.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes per day in each of our operating areas and total production for the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31,	
	2016	2015
Production volumes per day:(1)(2)		
Appalachia:(3)		
Natural gas (Mcfd)	31,545	35,158
Oil (Bpd)	295	359
NGLs (Bpd)	290	240
Total (Mcfed)	35,054	38,752
Coal-bed Methane:(3)		
Natural gas (Mcfd)	120,549	134,133
Oil (Bpd)	—	—
NGLs (Bpd)	—	—
Total (Mcfed)	120,549	134,133
Barnett/Marble Falls:		
Natural gas (Mcfd)	36,821	49,617
Oil (Bpd)	322	749
NGLs (Bpd)	1,457	2,274
Total (Mcfed)	47,497	67,755
Rangely:		
Natural gas (Mcfd)	—	—
Oil (Bpd)	2,354	2,361
NGLs (Bpd)	256	253
Total (Mcfed)	15,657	15,680
Eagle Ford:		
Natural gas (Mcfd)	389	500
Oil (Bpd)	1,362	1,550
NGLs (Bpd)	81	106
Total (Mcfed)	9,049	10,434
Mid-Continent:(3)		
Natural gas (Mcfd)	5,246	7,931
Oil (Bpd)	231	514
NGLs (Bpd)	425	615
Total (Mcfed)	9,178	14,709
Total production volumes per day:		
Natural gas (Mcfd)	194,550	227,340
Oil (Bpd)	4,563	5,533
NGLs (Bpd)	2,509	3,488
Total (Mcfed)	236,983	281,463
Total production:(1)(2)		
Natural gas (MMcf)	17,704	20,461

Oil (000’s Bbls)	415	498
NGLs (000’s Bbls)	228	314
Total (MMcfe)	21,565	25,332

26

(1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling Partnership's proportionate net revenue interest in these wells.

(2) "MMcf" represents million cubic feet; "MMcfe" represent million cubic feet equivalents; "Mcfd" represents thousand cubic feet per day; "Mcfed" represents thousand cubic feet equivalents per day; and "Bbls" and "Bpd" represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.

(3) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and the Niobrara Shale (northeastern Colorado).

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the three months ended March 31, 2016 and 2015 along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

	Three Months Ended March 31,	
	2016	2015
Production revenues (in thousands):(1)		
Appalachia:(2)		
Natural gas revenue	$3,795	$4,994
Oil revenue	1,201	2,213
Natural gas liquids revenue	25	241
Total revenues	$5,021	$7,448
Coal-bed Methane:(2)		
Natural gas revenue	$23,839	$47,841
Oil revenue	—	—
Natural gas liquids revenue	—	—
Total revenues	$23,839	$47,841
Barnett/Marble Falls:		
Natural gas revenue	$2,962	$11,882
Oil revenue	439	2,357
Natural gas liquids revenue	874	3,044
Total revenues	$4,275	$17,283
Rangely:		
Natural gas revenue	$—	$—
Oil revenue	7,724	16,073
Natural gas liquids revenue	489	988
Total revenues	$8,213	$17,061
Eagle Ford:		
Natural gas revenue	$90	$194

Oil revenue	5,860	9,907
Natural gas liquids revenue	86	110
Total revenues	$6,036	$10,211
Mid-Continent:[(2)]		
Natural gas revenue	$598	$1,630
Oil revenue	88	1,835
Natural gas liquids revenue	422	940
Total revenues	$1,108	$4,405
Total production revenues:		
Natural gas revenue	$31,284	$66,541
Oil revenue	15,312	32,385
Natural gas liquids revenue	1,896	5,323
Total revenues	$48,492	$104,249
Average sales price:		
Natural gas (per Mcf):[(3)]		
Total realized price, after hedge[(4) (5)]	$3.41	$3.58
Total realized price, before hedge[(4)]	$1.78	$2.54
Oil (per Bbl):[(3)]		

27

	Three Months Ended March 31,	
	2016	2015
Total realized price, after hedge[5]	$77.16	$80.81
Total realized price, before hedge	$29.51	$43.46
Natural gas liquids (per Bbl):[3]		
Total realized price, after hedge[5]	$8.31	$22.49
Total realized price, before hedge	$8.31	$14.10
Production costs (per Mcfe):[2] [3]		
Appalachia:		
Lease operating expenses[6]	$0.84	$1.07
Production taxes	0.06	0.07
Transportation and compression	0.24	0.32
	$1.14	$1.46
Coal-bed Methane:		
Lease operating expenses	$1.02	$1.06
Production taxes	0.16	0.24
Transportation and compression	0.32	0.32
	$1.50	$1.62
Barnett/Marble Falls:		
Lease operating expenses	$0.97	$1.41
Production taxes	0.17	0.18
Transportation and compression	0.21	0.07
	$1.34	$1.66
Rangely:		
Lease operating expenses	$4.36	$4.01
Production taxes	0.56	1.01
Transportation and compression	0.01	0.01
	$4.92	$5.03
Eagle Ford:		
Lease operating expenses	$1.75	$1.60
Production taxes	0.38	0.30
Transportation and compression	0.10	0.04
	$2.23	$1.94
Mid-Continent:		
Lease operating expenses	$1.58	$1.45
Production taxes	0.06	0.08
Transportation and compression	0.30	0.26
	$1.94	$1.79
Total production costs:		
Lease operating expenses[6]	$1.25	$1.35
Production taxes	0.18	0.24
Transportation and compression	0.26	0.23
	$1.69	$1.82

(1) Production revenue excludes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015, consisting of $28.5 million associated with natural gas derivative contracts and $16.7 million

associated with crude oil derivative contracts for the three months ended March 31, 2016, and $5.6 million associated with natural gas derivative contracts, $7.9 million associated with crude oil derivative contracts, and $1.7 million associated with natural gas liquids derivative contracts for the three months ended March 31, 2015 (see "Item 1. Financial Statements – Note 5").

(2) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and Niobrara Shale (northeastern Colorado).

(3) "Mcf" represents thousand cubic feet; "Mcfe" represents thousand cubic feet equivalents; and "Bbl" represents barrels.

(4) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the three months ended March 31, 2016 and 2015. Including the effect of this subordination, the average realized gas sales price was $3.37 per Mcf ($1.74 per Mcf before the effects of financial hedging) and $3.53 per Mcf ($2.48 per Mcf before the effects of financial hedging) for the three months ended March 31, 2016 and 2015, respectively.

(5) Includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015, consisting of $28.5 million associated with natural gas derivative contracts and $16.7 million associated with crude oil derivative contracts for the three months ended March 31, 2016, and $5.6 million associated with natural gas derivative contracts, $7.9 million associated with crude oil derivative contracts, and $1.7 million associated with natural gas liquids derivative contracts for the three months ended March 31, 2015 (see "Item 1. Financial Statements – Note 5").

(6) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for the three months ended March 31, 2016 and 2015. Including the effects of these costs, Appalachia lease operating expenses were $0.66 per Mcfe ($0.97 per Mcfe for total production costs) and $0.91 per Mcfe ($1.30 per Mcfe for total production costs) for the three months ended March 31, 2016 and 2015, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $1.23 per Mcfe ($1.66 per Mcfe for total production costs) and $1.33 per Mcfe ($1.80 per Mcfe for total production costs) for the three months ended March 31, 2016 and 2015, respectively.

	Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Gas and oil production revenues	$48,492	$104,249
Gas and oil production costs	$35,842	$45,498
Total production costs per Mcfe	$1.69	$1.82

The $55.8 million decrease in gas and oil production revenues consisted of a $24.0 million decrease attributable to our Coal-bed Methane operations, a $13.0 million decrease attributable to our Barnett Shale/Marble Falls operations, an $8.9 million decrease associated with our Rangely operations, a $4.2 million decrease attributable to our Eagle Ford operations, a $3.3 million decrease attributable to our Mid-Continent operations and a $2.4 million decrease attributable to our Appalachia operations.

The $9.7 million decrease in gas and oil production expenses primarily consisted of a $4.3 million decrease attributable to our Barnett Shale/Marble Falls operations, a $3.1 million decrease attributable to our Coal-bed Methane operations, a $1.4 million decrease attributable to our Appalachia operations, an $0.8 million decrease attributable to our Mid-Continent operations and a $0.1 million decrease attributable to our Rangely operations. Total production costs per Mcfe decreased between the periods primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling Partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for Drilling Partnerships we sponsor. The following table presents the amounts of Drilling Partnership investor capital raised and deployed, as well as sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

Three Months Ended

	March 31,	
	2016	2015
Drilling partnership investor capital:		
Raised	$—	$—
Deployed	$2,100	$23,655
Average construction and completion:		
Revenue per well	$4,200	$2,290
Cost per well	3,652	1,991
Gross profit per well	$548	$299
Gross profit margin	$274	$3,085
Partnership net wells associated with revenue recognized[(1)]:		
Appalachia - Utica	—	1
Marble Falls	—	