Atlas Resource Partners, L.P.
Form 10-Q
May 07, 2014

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, 2014

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 1000 Commerce Drive, Suite 400 Pittsburgh, Pennsylvania	15275
(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 x	Accelerated filer ¨
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 5, 2014 was 65,797,358.

ATLAS RESOURCE PARTNERS, L.P.

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ON FORM 10-Q

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ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	March 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$1,965	$ 1,828
Accounts receivable	78,127	58,822
Current portion of derivative asset	161	1,891
Subscriptions receivable	—	47,692
Prepaid expenses and other	17,481	10,097
Total current assets	97,734	120,330
Property, plant and equipment, net	2,125,189	2,120,818
Goodwill and intangible assets, net	32,679	32,747
Long-term derivative asset	23,749	27,084
Other assets, net	42,554	42,821
	$2,321,905	$ 2,343,800
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$94,472	$ 69,346
Advances from affiliates	24,413	26,742
Liabilities associated with drilling contracts	—	49,377
Current portion of derivative liability	22,372	6,353
Accrued well drilling and completion costs	66,199	40,481
Accrued interest	7,843	20,622
Accrued liabilities	31,118	30,794
Total current liabilities	246,417	243,715
Long-term debt	889,388	942,334
Asset retirement obligations	91,389	89,776
Other long-term liabilities	721	684
Commitments and contingencies		
Partners' Capital:		
General partner's interest	1,485	4,482
Preferred limited partners' interests	180,543	183,477
Class C common limited partner warrants	1,176	1,176

Common limited partners’ interests	905,888	852,457
Accumulated other comprehensive income	4,898	25,699
Total partners’ capital	1,093,990	1,067,291
	$2,321,905	$ 2,343,800

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31, 2014	2013
Revenues:		
Gas and oil production	$96,245	$46,064
Well construction and completion	49,377	56,478
Gathering and processing	4,468	3,585
Administration and oversight	1,729	1,085
Well services	5,479	4,816
Other, net	47	20
Total revenues	157,345	112,048
Costs and expenses:		
Gas and oil production	36,792	15,216
Well construction and completion	42,936	49,112
Gathering and processing	4,413	4,413
Well services	2,482	2,318
General and administrative	16,455	17,567
Depreciation, depletion and amortization	50,237	21,208
Total costs and expenses	153,315	109,834
Operating income	4,030	2,214
Interest expense	(13,188)	(6,889)
Loss on asset sales and disposal	(1,603)	(702)
Net loss	(10,761)	(5,377)
Preferred limited partner dividends	(4,399)	(1,957)
Net loss attributable to common limited partners and the general partner	$(15,160)	$(7,334)
Allocation of net income (loss) attributable to common limited partners and the general partner:		
Common limited partners’ interest	$(17,164)	$(7,635)
General partner’s interest	2,004	301
Net loss attributable to common limited partners and the general partner	$(15,160)	$(7,334)
Net loss attributable to common limited partners per unit:		
Basic and Diluted	$(0.28)	$(0.17)
Weighted average common limited partner units outstanding:		
Basic and Diluted	61,219	43,974

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Three Months Ended March 31,	
	2014	2013
Net loss	$(10,761)	$(5,377)
Other comprehensive income (loss):		
Changes in fair value of derivative instruments accounted for as cash flow hedges	(34,844)	(24,944)
Less: reclassification adjustment for realized (gains) losses of cash flow hedges in net loss	14,043	(993)
Total other comprehensive loss	(20,801)	(25,937)
Comprehensive loss attributable to common and preferred limited partners and the general partner	$(31,562)	$(31,314)

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

(in thousands, except unit data)

(Unaudited)

	General Partners' Interest		Preferred Limited Partners' Interest				Common Limited Partners' Interests		Class C Common Limited Partner Warrants		Accumulated Other Comprehen	To Pa
	Class A		Class B		Class C							
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Amount	Income	Ca
2014	1,368,058	$4,482	3,836,554	$96,539	3,749,986	$86,938	59,448,308	$852,457	562,497	$1,176	$25,699	$1
f	129,538	—	—	—	—	—	6,325,000	129,011	—	—	—	1
f nits ntive	—	—	—	—	—	—	22,375	—	—	—	—	–
nits ntive	—	—	—	—	—	—	—	2,300	—	—	—	2
ons	—	(1,055)	—	(742)	—	(724)	—	(12,875)	—	—	—	(
ons nd rtners neral on	—	(3,946)	—	(2,967)	—	(2,900)	—	(47,207)	—	—	—	(
l on nits ntive	—	—	—	—	—	—	—	(634)	—	—	—	(
e	—	2,004	—	2,224	—	2,175	—	(17,164)	—	—	—	(
nsive	—	—	—	—	—	—	—	—	—	—	(20,801)	(
2014	1,497,596	$1,485	3,836,554	$95,054	3,749,986	$85,489	65,795,683	$905,888	562,497	$1,176	$4,898	$1

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Three Months Ended March 31, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(10,761)	$(5,377)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	50,237	21,208
Loss on asset sales and disposal	1,603	702
Non-cash compensation expense	2,344	4,247
Amortization of deferred financing costs	1,758	4,644
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	16,111	40,828
Accounts payable and accrued liabilities	(38,611)	(66,936)
Net cash provided by (used in) operating activities	22,681	(684)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(39,897)	(58,487)
Other	(514)	11
Net cash used in investing activities	(40,411)	(58,476)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	162,000	121,000
Repayments under credit facilities	(215,000)	(327,425)
Net proceeds from issuance of long-term debt	—	267,926
Distributions paid to unitholders	(57,020)	(23,566)
Net proceeds from issuance of common limited partner units	129,011	—
Deferred financing costs, distribution equivalent rights and other	(1,124)	(825)
Net cash provided by financing activities	17,867	37,110
Net change in cash and cash equivalents	137	(22,050)
Cash and cash equivalents, beginning of year	1,828	23,188
Cash and cash equivalents, end of period	$1,965	$1,138

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

March 31, 2014

(Unaudited)

NOTE 1 – BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the “Partnership”) is a publicly traded Delaware master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas, crude oil and natural gas liquids (“NGL”) with operations in basins across the United States. The Partnership sponsors and manages tax-advantaged investment partnerships (the “Drilling Partnerships”), in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities. At March 31, 2014, Atlas Energy, L.P. (“ATLS”), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of the general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 33.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

The Partnership was formed in October 2011 to own and operate substantially all of ATLS’ exploration and production assets (“Atlas Energy E&P Operations”), which were transferred to the Partnership on March 5, 2012. In February 2012, the board of ATLS’ general partner approved the distribution of approximately 5.24 million of the Partnership’s common units which were distributed on March 13, 2012 to ATLS’ unitholders using a ratio of 0.1021 of the Partnership’s limited partner units for each of ATLS’ common units owned on the record date of February 28, 2012.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2013 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and 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. In management’s opinion, all adjustments necessary for a fair presentation of the Partnership’s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2013. Certain amounts in the prior year’s financial statements have been reclassified to conform to the current year presentation. The results of operations for the three months ended March 31, 2014 may not necessarily be indicative of the results of operations for the full year ending December 31, 2014.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership's consolidated balance sheets at March 31, 2014 and December 31, 2013 and the consolidated statements of operations for the three months ended March 31, 2014 and 2013 include the accounts of the Partnership and its 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. Transactions between the Partnership and other ATLS operations have been identified in the consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

In accordance with established practice in the oil and gas industry, the Partnership's consolidated financial statements include its pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the Drilling Partnerships in which the Partnership has an interest. Such interests generally approximate 30%. The Partnership's consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, the Partnership calculates these items specific to its own economics as further explained under the heading "Property, Plant and Equipment" elsewhere within this note.

Use of Estimates

The preparation of the Partnership's 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 the Partnership's consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership's consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired and liabilities assumed. Actual results could differ from those estimates.

The natural 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. Differences between estimated and actual amounts are recorded in the following month's financial results. Management believes that the operating results presented for the three months ended March 31, 2014 and 2013 represent actual results in all material respects (see "Revenue Recognition").

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. In evaluating the realizability of its accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by management's review of the Partnership's customers' credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At March 31, 2014 and December 31, 2013, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $9.6 million and $4.6 million of inventory at March 31, 2014 and December 31, 2013, respectively, which was included within prepaid expenses and other current assets on the Partnership's consolidated balance sheets. The Partnership values inventories at the lower of cost or market. The Partnership's inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs which generally do not extend the useful life of an asset for two years or more through the replacement of critical components are expensed as incurred. Major renewals and improvements which generally extend the useful life of an asset for two years or more through the replacement of critical components are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset's estimated useful life. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership's results of operations.

The Partnership follows the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs to enhance or evaluate development of proved fields or areas are capitalized. All other geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil and NGLs are converted to gas equivalent basis ("Mcfe") at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

The Partnership's depletion expense is determined on a field-by-field basis using the units-of-production method. Depletion rates for leasehold acquisition costs are based on estimated proved reserves, and depletion rates for well and related equipment costs are based on proved developed reserves associated with each field. Depletion rates are determined based on reserve quantity estimates and the capitalized costs of undeveloped and developed producing properties. Capitalized costs of developed producing properties in each field are aggregated to include the Partnership's costs of property interests in proportionately consolidated Drilling Partnerships, joint venture wells, wells drilled solely by the Partnership for its interests, properties purchased and working interests with other outside operators.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Partnership's consolidated statements of operations. Upon the sale of an individual well, the Partnership credits the proceeds to accumulated depreciation and depletion within its consolidated balance sheets. Upon the Partnership's sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the Partnership's consolidated statements of operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

The review of the Partnership's oil and gas properties is done on a field-by-field basis by determining if the historical cost of proved properties less the applicable accumulated depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Partnership's plans to continue to produce and develop proved reserves. Expected future cash flows from the sale of production of reserves are calculated based on estimated future prices. The Partnership estimates prices based upon current contracts in place, adjusted for basis differentials and market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, the Partnership's reserve estimates for its investment in the Drilling Partnerships are based on its own assumptions rather than its proportionate share of the limited partnerships' reserves. These assumptions include the Partnership's actual capital contributions, a disproportionate share of salvage value upon plugging of the wells and lower operating and administrative costs.

The Partnership's lower operating and administrative costs result from the limited partners in the Drilling Partnerships paying to the Partnership their proportionate share of these expenses plus a profit margin. These assumptions could result in the Partnership's calculation of depletion and impairment being different than its proportionate share of the Drilling Partnerships' calculations for these items. In addition, reserve estimates for wells with limited or no production history are less reliable than those based on actual production. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information which could cause the assumptions to be modified. The Partnership cannot predict what reserve revisions may be required in future periods.

The Partnership's method of calculating its reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships, which the Partnership sponsors and owns an interest in but does not control. The Partnership's reserve quantities include reserves in excess of its proportionate share of reserves in Drilling Partnerships, which the Partnership may be unable to recover due to the Drilling Partnerships' legal structure. The Partnership may have to pay additional consideration in the future as a Drilling Partnership's wells become uneconomic to the Drilling Partnership under the terms of the Drilling Partnership's drilling and operating agreement in order to recover these excess reserves, in addition to the Partnership becoming responsible for paying associated future operating, development and plugging costs of the well interests acquired, and to acquire any additional residual interests in the wells held by the Drilling Partnership's limited partners. The acquisition of any such uneconomic well interest from the Drilling Partnership by the Partnership is governed under the Drilling Partnership's limited partner agreement. In general, the Partnership will seek consent from the Drilling Partnership's limited partners to acquire the well interests from the Drilling Partnership based upon the Partnership's determination of fair market value.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. During the year ended December 31, 2013, the Partnership recognized $13.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet, primarily for its unproved acreage in the Chattanooga and New Albany Shales. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three months ended March 31, 2014 and 2013.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2013, the Partnership recognized $24.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the New Albany Shale. There were no impairments of proved gas and oil properties recorded by the Partnership for the three months ended March 31, 2014 and 2013.

The impairments of proved and unproved properties during the year ended December 31, 2013 related to the carrying amounts of these gas and oil properties being in excess of the Partnership’s estimate of their fair values at December 31, 2013 and management’s intention not to drill on certain expiring unproved acreage. The estimate of the fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

Capitalized Interest

The Partnership capitalizes 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 the Partnership was 5.6% and 6.2% for the three months ended March 31, 2014 and 2013, respectively. The aggregate amount of interest capitalized by the Partnership was $2.6 million and $3.4 million for the three months ended March 31, 2014 and 2013, respectively.

Intangible Assets

The Partnership recorded its intangible assets with finite lives in connection with partnership management and operating contracts acquired through prior consummated acquisitions. The Partnership amortizes contracts acquired on a declining balance method over their respective estimated useful lives.

The following table reflects the components of intangible assets being amortized at March 31, 2014 and December 31, 2013 (in thousands):

	March 31, 2014	December 31, 2013	Estimated Useful Lives In Years
Gross Carrying Amount	$ 14,344	$ 14,344	13
Accumulated Amortization	(13,449)	(13,381)	
Net Carrying Amount	$ 895	$ 963	

Amortization expense on intangible assets was $0.1 million for both the three months ended March 31, 2014 and 2013. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2014 - $0.3 million; 2015 - $0.2 million; 2016 - $0.1 million, 2017 - $0.1 million and 2018 - $0.1 million.

Goodwill

At March 31, 2014 and December 31, 2013, the Partnership had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions. No changes in the carrying amount of goodwill were recorded for the three months ended March 31, 2014 and 2013.

The Partnership tests goodwill for impairment at each year end by comparing its reporting units' estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership's management must apply judgment in determining the estimated fair value of these reporting units. The Partnership's management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership's assets and the available market data of the industry group. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership's market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership's management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership's industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership's industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise. During the three months ended March 31, 2014 and 2013, no impairment indicators arose, and no goodwill impairments were recognized by the Partnership.

Asset Retirement Obligations

The Partnership recognizes an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities (see Note 6). The Partnership recognizes a liability for its future asset retirement obligations in the current period if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

Income Taxes

The Partnership is not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership's taxable income. Such taxable income may vary substantially from net income reported in the accompanying consolidated financial statements. Certain corporate subsidiaries of the Partnership are subject to federal and state income tax. The federal and state income taxes related to the Partnership and these corporate subsidiaries were immaterial to the consolidated financial statements and are recorded in pre-tax income on a current basis only. Accordingly, no federal or state deferred income tax has been provided for in the accompanying consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the three months ended March 31, 2014 and 2013.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of March 31, 2014.

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) 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 (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, income (loss) attributable to preferred limited partners and net income (loss) attributable to the General Partner's Class A units. The General Partner's interest in net income (loss) is calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 13), 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 (loss) allocated with respect to the General Partner's and limited partners' ownership interests.

The Partnership presents net income (loss) 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 when considered in the calculation of earnings per unit under the two-class method. 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, management of the Partnership believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Unvested share-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 its long-term incentive plan (see Note 14), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights would result in a non-contingent transfer of value each time the Partnership declares 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 (loss) 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 loss allocated to the common limited partners for purposes of calculating net loss attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended March 31,

	2014	2013
Net loss	$ (10,761)	$ (5,377)
Preferred limited partner dividends	(4,399)	(1,957)
Net loss attributable to common limited partners and the general partner	(15,160)	(7,334)
Less: General partner’s interest	(2,004)	(301)
Net loss attributable to common limited partners	(17,164)	(7,635)
Less: Net income attributable to participating securities – phantom units[1]	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit	$ (17,164)	$ (7,635)

(1) Net income attributable to common limited partners’ ownership interests is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended March 31, 2014 and 2013, net loss attributable to common limited partners’ ownership interest is not allocated to approximately 820,000 and 998,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) 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 method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership's long-term incentive plan (see Note 14).

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

	Three Months Ended March 31,	
	2014	2013
Weighted average number of common limited partner units - basic	61,219	43,974
Add effect of dilutive incentive awards[(1)]	—	—
Add effect of dilutive convertible preferred limited partner units and warrants[(2)]	—	—
Weighted average number of common limited partner units - diluted	61,219	43,974

(1) For the three months ended March 31, 2014 and 2013, approximately 820,000 units and 998,000 units, respectively, 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.

(2) For the three months ended March 31, 2014 and 2013, potential common limited partner units issuable upon conversion of the Partnership's Class B 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. For the three months ended March 31, 2014, potential common limited partner units issuable upon conversion of the Partnership's 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. For the three months ended March 31, 2014, potential common limited partner units issuable upon 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.

Revenue Recognition

Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Partnership contracts with the Drilling Partnerships to drill partnership wells. The contracts require that the Drilling Partnerships pay the Partnership the full contract price upon execution. The income from a drilling contract is recognized as the services are performed using the percentage of completion method. The contracts are typically completed between 60 and 270 days. On an uncompleted contract, the Partnership classifies the difference between the contract payments it has received and the revenue earned as a current liability titled "Liabilities Associated with Drilling Contracts" on the Partnership's consolidated balance sheets. The Partnership recognizes well services revenues at the time the services are performed. The Partnership is also entitled to receive management fees according to the respective partnership agreements and recognizes such fees as income when earned, which are included in administration and oversight revenues within its consolidated statements of operations.

The Partnership generally sells natural gas, crude oil and NGLs at prevailing market prices. Typically, the Partnership's sales contracts are based on pricing provisions that are tied to a market index, with certain fixed adjustments based on proximity to gathering and transmission lines and the quality of its natural gas. Generally, the market index is fixed two business days prior to the commencement of the production month. Revenue and the related accounts receivable are recognized when produced quantities are delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Revenues from the production of natural gas, crude oil and NGLs, in which the Partnership has an interest with other producers, are recognized on the basis of its percentage ownership of the working interest and/or overriding royalty.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Partnership's records and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see "Use of Estimates" for further description). The Partnership had unbilled revenues at March 31, 2014 and December 31, 2013 $83.0 million and $55.3 million, respectively, which were included in accounts receivable within the Partnership's consolidated balance sheets.

Gathering and processing revenue includes gathering fees the Partnership charges to the Drilling Partnership wells for the Partnership's processing plants in the New Albany Shale and the Chattanooga Shale. Generally, the Partnership charges a gathering fee to the Drilling Partnership wells equivalent to the fees the Partnership remits. In Appalachia, a majority of the Drilling Partnership wells are subject to a gathering agreement, whereby the Partnership remits a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, the Partnership charges the Drilling Partnership wells a 13% gathering fee. As a result, some of the Partnership's gathering expenses, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as "other comprehensive income (loss)" on the Partnership's consolidated financial statements, and at March 31, 2014, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 8). The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss).

Recently Adopted Accounting Standards

In July 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2013-11, Income Taxes (Topic 740) – Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists ("Update 2013-11"), which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption was permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership adopted the requirements of Update 2013-11 upon its effective date of January 1, 2014, and it had no material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date ("Update 2013-04"). Update 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements, for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations and settled litigation and judicial rulings. Update 2013-04 requires an entity to measure joint and several liability arrangements, for which the total amount of the obligation is fixed at the reporting date as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, Update 2013-04 provides disclosure guidance on the nature and amount of the obligation as well as other information. Update 2013-04 is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. The Partnership adopted the requirements of Update 2013-04 upon its effective date of January 1, 2014, and it had no material impact on its financial position, results of operations or related disclosures.

NOTE 3 – ACQUISITIONS

EP Energy Acquisition

On July 31, 2013, the Partnership completed an acquisition of assets from EP Energy E&P Company, L.P. (“EP Energy”) for approximately $709.6 million in cash, net of purchase price adjustments (the “EP Energy Acquisition”). The purchase price was funded through borrowings under the Partnership’s revolving credit facility, the issuance of the Partnership’s 9.25% senior notes due August 15, 2021 (see Note 7), and the issuance of 14,950,000 common limited partner units and 3,749,986 newly created Class C convertible preferred units (see Note 12). The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013. The Partnership’s consolidated financial statements reflected the operating results of the acquired business commencing July 31, 2013.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $12.1 million of transaction fees which were included within common limited partners' interests for the year ended December 31, 2013 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

The following table presents the preliminary values assigned to the assets acquired and liabilities assumed in the acquisition, based on their estimated fair values at the date of the acquisition (in thousands):

Assets:	
Prepaid expenses and other	$5,268
Property, plant and equipment	723,657
Total current assets	$728,925
Liabilities:	
Accounts payable	2,562
Asset retirement obligation	16,728
Total liabilities assumed	19,290
Net assets acquired	$709,635

Other Acquisitions

On February 13, 2014, the Partnership entered into a definitive asset purchase and sale agreement to acquire certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for approximately $107.0 million in cash with an effective date of January 1, 2014, subject to certain purchase price adjustments. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia. On May 5, 2014, closing of the transaction was approved by GeoMet's shareholder vote, and is expected to occur during the second quarter of 2014, subject to certain customary closing conditions.

On September 20, 2013, the Partnership completed the acquisition of certain assets from Norwood Natural Resources ("Norwood") for $5.4 million (the "Norwood Acquisition"). The assets acquired included Norwood's non-operating working interest in certain producing wells in the Barnett Shale. The Norwood Acquisition had an effective date of June 1, 2013.

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2014	December 31, 2013	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$321,179	$ 320,459	
Pre-development costs	4,038	4,367	
Wells and related equipment	2,204,347	2,164,760	
Total proved properties	2,529,564	2,489,586	
Unproved properties	216,598	211,536	
Support equipment	26,403	23,005	
Total natural gas and oil properties	2,772,565	2,724,127	
Pipelines, processing and compression facilities	43,135	42,949	2 – 40
Rights of way	829	830	20 – 40
Land, buildings and improvements	8,981	9,462	3 – 40
Other	16,185	15,318	3 – 10
	2,841,695	2,792,686	
Less – accumulated depreciation, depletion and amortization	(716,506)	(671,868)	
	$2,125,189	$ 2,120,818	

During the three months ended March 31, 2014, the Partnership recognized $1.6 million of loss on asset disposal primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement. During the three months ended March 31, 2013, the Partnership recognized $0.7 million of loss on asset disposal pertaining to its decision not to drill wells on leasehold property that expired during the three months ended March 31, 2013 in Indiana and Tennessee.

During the year ended December 31, 2013, the Partnership recognized $38.0 million of asset impairments related to its oil and gas properties within property, plant and equipment, net on its consolidated balance sheet primarily for its shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. These impairments related to the carrying amounts of gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2013, and management's intention not to drill on certain expiring unproved acreage. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

NOTE 5 – OTHER ASSETS

The following is a summary of other assets at the dates indicated (in thousands):

	March 31, 2014	December 31, 2013
Deferred financing costs, net of accumulated amortization of $13,706 and $11,948 at March 31, 2014 and December 31, 2013, respectively	$ 34,077	$ 35,292
Notes receivable	4,012	3,978
Long-term derivative asset receivable from Drilling Partnerships	1,007	863
Other	3,458	2,688
	$ 42,554	$ 42,821

Deferred financing costs are recorded at cost and amortized over the term of the respective debt agreements (see Note 7). Amortization expense of deferred financing costs was $1.8 million and $1.4 million for the three months ended March 31, 2014 and 2013, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the three months ended March 31, 2013, the Partnership also recognized $3.2 million for accelerated amortization of deferred financing costs associated with the retirement of its then-existing term loan facility and a portion of the outstanding indebtedness under its revolving credit facility with a portion of the proceeds from its issuance of its 7.75% senior notes due 2021 (see Note 7).

At March 31, 2014 and December 31, 2013, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership's consolidated balance sheets. The notes have a maturity date of March 31, 2022, and a 2.25% per annum interest rate. The maturity date of the notes can be extended to March 31, 2027, subject to certain conditions, including an extension fee of 1.0% of the outstanding principal balance. For the three months ended March 31, 2014, approximately $23,000 of interest income was recognized within other, net on the Partnership's consolidated statements of operations. There was no interest income recognized for the three months ended March 31, 2013. At March 31, 2014, the Partnership recorded no allowance for credit losses within its consolidated balance sheets based upon payment history and ongoing credit evaluations associated with the notes receivable.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

The Partnership recognized an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities. The Partnership also recognized a liability for its future asset retirement obligations if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability for asset retirement obligations was based on the Partnership's historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The liability was discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. The Partnership has no assets legally restricted for purposes of settling asset retirement obligations. Except for its gas and oil properties, the Partnership determined that there were no other material retirement obligations associated with tangible long-lived assets.

The Partnership proportionately consolidates its ownership interest of the asset retirement obligations of its Drilling Partnerships. At March 31, 2014, the Drilling Partnerships had $57.9 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of the Partnership's proportional interest in such liabilities. Under the terms of the respective partnership agreements, the Partnership maintains the right to retain a portion or all of the distributions to the limited partners of its Drilling Partnerships to cover the limited partners' share of the plugging and abandonment costs up to a specified amount per month. During the three months ended March 31, 2014, the Partnership withheld $0.6 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. No amounts were withheld during the three months ended March 31, 2013. The Partnership's historical practice and continued intention is to retain distributions from the limited partners as the wells within each Drilling Partnership near the end of their useful life. On a partnership-by-partnership basis, the Partnership assesses its right to withhold amounts related to plugging and abandonment costs based on several factors including commodity price trends, the natural decline in the production of the wells, and current and future costs. Generally, the Partnership's intention is to retain distributions from the limited partners as the fair value of the future cash flows of the limited partners' interest approaches the fair value of the future plugging and abandonment cost. Upon the Partnership's decision to retain all future distributions to the limited partners of its Drilling Partnerships, the Partnership will assume the related asset retirement obligations of the limited partners.

A reconciliation of the Partnership’s liability for well plugging and abandonment costs for the periods indicated is as follows (in thousands):

	Three Months Ended March 31,	
	2014	2013
Asset retirement obligations, beginning of year	$ 89,776	$ 64,794
Liabilities incurred	529	645
Liabilities settled	(217)	(7)
Accretion expense	1,301	954
Asset retirement obligations, end of period	$ 91,389	$ 66,386

The above accretion expense was included in depreciation, depletion and amortization in the Partnership’s consolidated statements of operations and the asset retirement obligation liabilities were included within asset retirement obligations in the Partnership’s consolidated balance sheets. During the year ended December 31, 2013, the Partnership incurred $16.7 million of future plugging and abandonment costs related to the EP Energy Acquisition it consummated during the period.

NOTE 7 - DEBT

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

	March 31, 2014	December 31, 2013
Revolving credit facility	$ 366,000	$ 419,000
7.75 % Senior Notes – due 2021	275,000	275,000
9.25 % Senior Notes – due 2021	248,388	248,334
Total debt	889,388	942,334
Less current maturities	—	—
Total long-term debt	$ 889,388	$ 942,334

Credit Facility

At March 31, 2014, the Partnership has a credit agreement with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the “Credit Agreement”) that provides for a senior secured revolving credit facility with a maximum facility amount of $1.5 billion scheduled to mature in July 2018. The Partnership’s borrowing base under the credit facility, which was $735.0 million at March 31, 2014, is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. At March 31, 2014, $366.0 million was outstanding under the credit facility. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $3.7 million was outstanding at March 31, 2014. The Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by certain of the Partnership's material subsidiaries, and any non-guarantor subsidiaries of the Partnership are minor. Borrowings under the credit facility bear interest, at the Partnership's election, at either an adjusted LIBOR rate plus an applicable margin between 1.75% and 2.75% per annum or the base rate (which is the higher of the bank's prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 0.75% and 1.75% per annum. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.5% per annum if 50% or more of the borrowing base is utilized and 0.375% per annum if less than 50% of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At March 31, 2014, the weighted average interest rate on outstanding borrowings under the credit facility was 2.3%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of March 31, 2014. The Credit Agreement also requires the Partnership to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended March 31, 2014 and June 30, 2014, 4.25 to 1.0 as of the last day of the quarter ending September 30, 2014, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. Based on the definitions contained in the Partnership's Credit Agreement, at March 31, 2014, the Partnership's ratio of current assets to current liabilities was 2.1 to 1.0, and its ratio of Total Funded Debt to EBITDA was 3.9 to 1.0.

Senior Notes

On July 30, 2013, the Partnership issued $250.0 million of its 9.25% senior notes due August 15, 2021 ("9.25% Senior Notes"), in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million. The net proceeds were used to partially fund the EP Energy Acquisition (see Note 3). The 9.25% Senior Notes were presented net of a $1.6 million unamortized discount as of March 31, 2014. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date on February 15, 2014. At any time on or after August 15, 2017, the Partnership may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, the Partnership may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the 9.25% Senior Notes due 2021, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (the "SEC") to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 30, 2014. On March 28, 2014, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was completed on April 29, 2014.

On January 23, 2013, the Partnership issued $275.0 million of its 7.75% senior notes due 2021 ("7.75% Senior Notes") in a private placement transaction at par. The Partnership used the net proceeds of approximately $267.6 million to repay all of the indebtedness and accrued interest outstanding under its then-existing term loan credit facility and a portion of the amounts outstanding under its revolving credit facility. In connection with the retirement of the Partnership's term loan credit facility and the reduction in its revolving credit facility borrowing base, the Partnership accelerated $3.2 million of amortization expense related to deferred financing costs during the three months ended March 31, 2013 (see Note 5). Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019.

On July 1, 2013, the Partnership filed a registration statement relating to the exchange offer for the 7.75% Senior Notes and the exchange offer was completed on January 2, 2014.

The 9.25% Senior Notes and 7.75% Senior Notes are guaranteed by certain of the Partnership’s material subsidiaries. The guarantees under the 9.25% Senior Notes and 7.75% Senior Notes are full and unconditional and joint and several, and any subsidiaries of the Partnership, other than the subsidiary guarantors, are minor. There are no restrictions on the Partnership’s ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 9.25% Senior Notes and 7.75% Senior Notes contain covenants, including limitations of the Partnership's 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 the Partnership's assets. The Partnership was in compliance with these covenants as of March 31, 2014.

Cash payments for interest by the Partnership were $26.5 million and $2.4 million for the three months ended March 31, 2014 and 2013, respectively.

NOTE 8 – DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps, collars and options, in connection with its commodity and interest rate price risk management activities. Management enters into financial instruments to hedge forecasted commodity sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under commodity-based swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. To manage the risk of regional commodity price differences, the Partnership occasionally enters into basis swaps. Basis swaps are contractual arrangements that guarantee a price differential for a commodity from a specified delivery point price and the comparable national exchange price. For natural gas basis swaps, which have negative differentials to NYMEX, the Partnership receives or pays a payment from the counterparty if the price differential to NYMEX is greater or less than the stated terms of the contract. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right, but not the obligation, to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

Management formally documents all relationships between the Partnership's hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching the commodity derivative contracts to the forecasted transactions. Management assesses, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying item being hedged, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which are determined by management of the Partnership through the utilization of market data, will be recognized immediately within other, net in the Partnership's consolidated statements of operations. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value of derivative instruments as accumulated other comprehensive income and reclassifies the portion relating to commodity derivatives to gas and oil production revenues within the Partnership's consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, management recognizes changes in fair value within other, net in the Partnership's consolidated statements of operations as they occur.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership's consolidated balance sheets as the initial value of the options. The Partnership reflected net derivative assets on its consolidated balance sheets of $1.5 million and $22.6 million at March 31, 2014 and December 31, 2013, respectively. Of the $4.9 million of net gain in accumulated other comprehensive income on the Partnership's consolidated balance sheet at March 31, 2014, if the fair values of the instruments remain at current market values, the Partnership will reclassify $22.4 million of losses to gas and oil production revenue on its consolidated statement of operations over the next twelve month period as these contracts expire. Aggregate gains of $27.3 million of gas and oil production revenues will be reclassified to the Partnership's consolidated statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future commodity price changes. No amounts were reclassified from other comprehensive income related to derivative instruments entered into during the three months ended March 31, 2014 and 2013.

The following table summarizes the gains recognized in the Partnership's consolidated statements of operations for effective derivative instruments for the periods indicated (in thousands):

	Three Months Ended March 31,	
	2014	2013
(Gain) loss reclassified from accumulated other comprehensive income (loss):		
Gas and oil production revenue	$ 14,043	$ (993)
Total	$ 14,043	$ (993)

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

Offsetting Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Assets Presented in the Consolidated Balance Sheets
As of March 31, 2014			
Current portion of derivative assets	$ 161	$ —	$ 161
Long-term portion of derivative assets	25,859	(2,110)	23,749
Current portion of derivative liabilities	4,382	(4,382)	—
Long-term portion of derivative liabilities	114	$ (114)	$ —
Total derivative assets	$ 30,516	(6,606)	23,910
As of December 31, 2013			
Current portion of derivative assets	$ 2,664	$ (773)	$ 1,891
Long-term portion of derivative assets	31,146	(4,062)	27,084
Current portion of derivative liabilities	4,341	(4,341)	—
Long-term portion of derivative liabilities	122	(122)	—
Total derivative assets	$ 38,273	$ (9,298)	$ 28,975

Offsetting Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Balance Sheets
As of March 31, 2014			
Current portion of derivative assets	$ —	$ —	$ —
Long-term portion of derivative assets	(2,110)	2,110	—
Current portion of derivative liabilities	(26,754)	4,382	(22,372)
Long-term portion of derivative liabilities	(127)	114	(13)
Total derivative liabilities	$ (28,991)	$ 6,606	$ (22,385)
As of December 31, 2013			
Current portion of derivative assets	$ (773)	$ 773	$ —

Long-term portion of derivative assets	(4,062)	4,062	—
Current portion of derivative liabilities	(10,694)	4,341	(6,353)
Long-term portion of derivative liabilities	(189)	122	(67)
Total derivative liabilities	$ (15,718)	$ 9,298	$ (6,420)

The Partnership enters into commodity future option and collar contracts to achieve more predictable cash flows by hedging its exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile 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 have qualified and been designated as cash flow hedges and were recorded at their fair values.

The Partnership recognized losses of $14.0 million and gains of $1.0 million for the three months ended March 31, 2014 and 2013, respectively, on settled contracts covering commodity production. These gains and losses were included within gas and oil production revenue in the Partnership's consolidated statements of operations. As the underlying prices and terms in the Partnership's derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the three months ended March 31, 2014 and 2013, respectively, for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At March 31, 2014, the Partnership had the following commodity derivatives:

Natural Gas Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset/ (Liability) (in thousands)(2)
2014	45,114,700	$ 4.152	$ (14,068)
2015	51,924,500	$ 4.239	1,799
2016	45,746,300	$ 4.311	7,193
2017	24,840,000	$ 4.532	6,734
2018	3,960,000	$ 4.716	1,306
			$ 2,964

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)	Fair Value Asset/ (Liability) (in thousands)(2)
2014	Puts purchased	2,880,000	$ 4.221	$ 642
2014	Calls sold	2,880,000	$ 5.120	(418)
2015	Puts purchased	3,480,000	$ 4.234	1,636

2015	Calls sold	3,480,000	$ 5.129	(721)
				$ 1,139

Natural Gas Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset (in thousands)(2)
2014	Puts purchased	1,350,000	$ 3.800	$ 84
2015	Puts purchased	1,440,000	$ 4.000	447
2016	Puts purchased	1,440,000	$ 4.150	613
				$ 1,144

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WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Liability (in thousands)(2)
2014	8,100,000	$ (0.110)	$ (42)
			$ (42)

Natural Gas Liquids Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Asset/ (Liability) (in thousands)(3)
2014	79,500	$ 91.568	$ (486)
2015	96,000	$ 88.550	(129)
2016	84,000	$ 85.651	92
2017	60,000	$ 83.780	127
			$ (396)

Natural Gas Liquids Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(4)
2014	1,890,000	$ 0.303	$ 25
			$ 25

Natural Gas Liquids Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Liability (in thousands)(5)
2014	9,261,000	$ 1.000	$ (727)
2015	8,064,000	$ 1.016	(149)
			$ (876)

Natural Gas Liquids Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Asset (in thousands)[6]
2014	1,134,000	$ 1.308	$ 35
2015	1,512,000	$ 1.248	28
			$ 63

Natural Gas Liquids Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Asset (in thousands)[7]
2014	1,134,000	$ 1.323	$ 33
2015	1,512,000	$ 1.263	24
			$ 57

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Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]	Fair Value Asset/ (Liability) (in thousands)[3]
2014	409,500	$ 92.692	$ (2,091)
2015	567,000	$ 88.144	(969)
2016	225,000	$ 85.523	218
2017	132,000	$ 83.305	220
			$ (2,622)

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)[1]	Average Floor and Cap (per Bbl)[1]	Fair Value Asset/ (Liability) (in thousands)[3]
2014	Puts purchased	30,870		