Atlas Resource Partners, L.P.
Form 10-Q
November 09, 2015

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 September 30, 2015

OR

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

Commission file number: 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.)
	15275

Park Place Corporate Center One
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 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 November 4, 2015 was 102,154,241.

ATLAS RESOURCE PARTNERS, L.P.

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ON FORM 10-Q

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$2,418	$15,247
Accounts receivable	89,402	114,520
Advances to affiliates	1,178	—
Current portion of derivative asset	146,622	144,259
Subscriptions receivable	23,054	32,398
Prepaid expenses and other	25,407	26,296
Total current assets	288,081	332,720
Property, plant and equipment, net	1,534,718	2,263,820
Goodwill and intangible assets, net	14,154	14,330
Long-term derivative asset	205,979	130,602
Other assets, net	53,826	50,081
	$2,096,758	$2,791,553
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$82,209	$111,198
Advances from affiliates	—	2,249
Liabilities associated with drilling contracts	—	40,611
Current portion of derivative payable to Drilling Partnerships	1,881	932
Accrued well drilling and completion costs	56,300	80,404
Accrued interest	10,785	26,452
Distribution payable	14,234	20,876
Deferred acquisition purchase price	21,667	23,445
Accrued liabilities	42,669	33,406
Total current liabilities	229,745	339,573
Long-term debt	1,505,047	1,394,460
Asset retirement obligations	112,435	107,950

Other long-term liabilities	4,654	2,033
Commitments and contingencies		
Partners' Capital:		
General partner's interest	(27,465)	(13,697)
Preferred limited partners' interests	188,910	163,522
Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	35,854	605,065
Accumulated other comprehensive income	46,402	191,471
Total partners' capital	244,877	947,537
	$2,096,758	$2,791,553

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues:				
Gas and oil production	$90,734	$129,399	$292,243	$337,893
Well construction and completion	23,054	61,204	63,665	126,917
Gathering and processing	1,685	3,061	6,046	11,287
Administration and oversight	5,495	6,177	7,301	12,072
Well services	5,842	6,597	18,568	18,441
Gain on mark-to-market derivatives	131,065	—	209,706	—
Other, net	20	261	80	343
Total revenues	257,895	206,699	597,609	506,953
Costs and expenses:				
Gas and oil production	41,591	51,391	130,224	133,038
Well construction and completion	20,046	53,221	55,361	110,363
Gathering and processing	2,473	3,214	7,406	11,900
Well services	2,398	2,617	6,735	7,525
General and administrative	13,978	13,124	44,400	50,894
Depreciation, depletion and amortization	40,463	64,578	125,948	176,077
Asset impairment	672,246	—	672,246	—
Total costs and expenses	793,195	188,145	1,042,320	489,797
Operating income (loss)	(535,300)	18,554	(444,711)	17,156
Interest expense	(25,192)	(16,577)	(75,105)	(43,028)
Loss on asset sales and disposal	(362)	(92)	(276)	(1,686)
Net income (loss)	(560,854)	1,885	(520,092)	(27,558)
Preferred limited partner dividends	(4,293)	(4,475)	(12,180)	(13,298)
Net loss attributable to common limited partners and the general partner	$(565,147)	$(2,590)	$(532,272)	$(40,856)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners’ interest	$(553,844)	$(5,599)	$(521,627)	$(48,283)
General partner’s interest	(11,303)	3,009	(10,645)	7,427
	$(565,147)	$(2,590)	$(532,272)	$(40,856)

Net loss attributable to common limited partners and the general partner				
Net loss attributable to common limited partners per unit:				
Basic	$(5.73)	$(0.07)	$(5.74)	$(0.67)
Diluted	$(5.73)	$(0.07)	$(5.74)	$(0.67)
Weighted average common limited partner units outstanding:				
Basic	96,660	81,521	90,943	72,288
Diluted	96,660	81,521	90,943	72,288

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$(560,854)	$1,885	$(520,092)	$(27,558)
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	—	70,362	—	5,268
Reclassification adjustment for unrealized gains used to offset impairment expense	(68,021)	—	(68,021)	—
Less: reclassification adjustment for realized (gains) losses of cash flow hedges in net income (loss)	(23,927)	(1,388)	(77,048)	22,703
Total other comprehensive income (loss)	(91,948)	68,974	(145,069)	27,971
Comprehensive income (loss) attributable to common and preferred limited partners and the general partner	$(652,802)	$70,859	$(665,161)	$413

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS’ CAPITAL

(in thousands, except unit data)

(Unaudited)

est	Preferred Limited Partners’ Interest								Common Limited Partners’ Interests		Class C Com Limited Partner Warra	
	Class B		Class C		Class D		Class E					
mount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	An
(13,697)	39,654	$983	3,749,986	$85,501	3,200,000	$77,038	—	$—	85,346,941	$605,065	562,497	$1
—	—	—	—	—	—	—	—	—		(44,893)	—	–
—	—	—	—	—	890,328	20,997	256,083	5,930	14,904,934	89,409	—	–
—	—	—	—	—	—	—	—		459,189	4,600	—	–
1,142	—	8	—	100	—	(231)	—	(172)	—	5,830	—	–
(4,265)	—	(42)	—	(5,937)	—	(6,287)	—	(173)	—	(102,999)	—	–
—	—	—	—	—	—	—	—	—	—	(516)	—	–
—	(39,654)	(985)	—	—	—	—	—	—	39,859	985	—	–
(10,645)	—	36	—	5,738	—	6,088	—	318	—	(521,627)	—	–
—	—	—	—	—	—	—	—	—	—	—	—	–

(27,465)	—	$—	3,749,986	$85,402	4,090,328	$97,605	256,083	$5,903	100,750,923	$35,854	562,497	$1

See accompanying notes to consolidated financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(520,092)	$(27,558)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	125,948	176,077
Asset impairment	672,246	—
Unrealized gain on derivatives	(192,447)	—
(Gain) loss on asset sales and disposal	(190)	1,686
Non-cash compensation expense	4,497	6,291
Amortization of deferred financing costs	13,151	6,098
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	148,879	(90,204)
Accounts payable and accrued liabilities	(150,684)	14,695
Net cash provided by operating activities	101,308	87,085
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(102,290)	(150,579)
Net cash paid for acquisitions	(36,967)	(510,029)
Other	394	(98)
Net cash used in investing activities	(138,863)	(660,706)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	560,341	1,034,000
Repayments under credit facilities	(449,754)	(793,000)
Distributions paid to unitholders	(119,703)	(162,290)
Net proceeds from long term debt	—	97,386
Net proceeds from issuance of common limited partner units	89,409	426,253
Net proceeds from issuance of preferred units	6,927	—
Arkoma transaction adjustment	(44,893)	(12,266)
Deferred financing costs, distribution equivalent rights and other	(17,601)	(13,123)
Net cash provided by financing activities	24,726	576,960
Net change in cash and cash equivalents	(12,829)	3,339
Cash and cash equivalents, beginning of year	15,247	1,828
Cash and cash equivalents, end of period	$2,418	$5,167

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2015

(Unaudited)

NOTE 1 – BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the "Partnership") is 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. 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.

On February 27, 2015, the Partnership's general partner, Atlas Energy Group, LLC ("Atlas Energy Group"; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. ("Atlas Energy"), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as "ATLS"). Atlas Energy Group manages the Partnership's operations and activities through its ownership of the Partnership's general partner interest. Concurrent with Atlas Energy Group's unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. ("Targa"; NYSE: TRGP) and ceased trading. At September 30, 2015, Atlas Energy Group owned 100% of the Partnership's general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 23.6% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

In addition to its general and limited partner interest in the Partnership, 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.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2014 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, 2014. 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 and nine months ended September 30, 2015 may not necessarily be indicative of the results of operations for the full year ending December 31, 2015.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership's consolidated balance sheets at September 30, 2015 and December 31, 2014 and the consolidated statements of operations for the three and nine months ended September 30, 2015 and 2014 include the accounts of the Partnership and its wholly-owned subsidiaries. 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.

On June 5, 2015, the Partnership acquired coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma from ATLS ("Arkoma Acquisition"). Management of the Partnership 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 on the Partnership's consolidated balance sheets. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the acquisition of Arkoma assets would have been included in the Partnership's 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 its prior period consolidated financial statements to furnish comparative information. As such, the Partnership reflected the impact of the Arkoma Acquisition on its 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;
- Retrospectively adjusted its consolidated financial statements for any date prior to June 5, 2015, the date of acquisition, to reflect its 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 the Partnership's consolidated statements of operations for the three and nine months ended September 30, 2014 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.

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 (see "Property, Plant and Equipment").

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 and nine months ended September 30, 2015 and 2014 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 accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customers' 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 September 30, 2015 and December 31, 2014, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had \$8.7 million and \$8.9 million of inventory at September 30, 2015 and December 31, 2014, 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 that 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 that 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 Property, Plant and Equipment

The Partnership reviews its property, plant and equipment 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 future 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 recognizing its proportionate share of limited partners' Drilling Partnership external operating expenses. 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 partnership 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.

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 6.5% and 5.4% for the three months ended September 30, 2015 and 2014, respectively, and 6.4% and 5.7% for the nine months ended September 30, 2015 and 2014, respectively. The aggregate amount of interest capitalized by the Partnership was \$4.0 million and \$3.7 million for the three months ended September 30, 2015 and 2014, respectively, and \$12.0 million and \$9.4 million for the nine months ended September 30, 2015 and 2014, 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. ARP reviews intangible 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 following table reflects the components of intangible assets being amortized at September 30, 2015 and December 31, 2014 (in thousands):

	September 30,	December 31,	Estimated Useful Lives

	2015	2014	In Years
Gross Carrying Amount	$ 14,344	$ 14,344	13
Accumulated Amortization	(13,829)	(13,653)	
Net Carrying Amount	$ 515	$ 691	

Amortization expense on intangible assets was $0.1 million for both the three months ended September 30, 2015 and 2014. Amortization expense on intangible assets was $0.2 million for both the nine months ended September 30, 2015 and 2014. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2015 - $0.2 million; 2016 - $0.1 million; 2017 - $0.1 million; 2018 - $0.1 million; and 2019 - $0.1 million.

Goodwill

At September 30, 2015 and December 31, 2014, the Partnership had $13.6 million of goodwill recorded in connection with its prior consummated acquisitions. No changes in the carrying amount of goodwill were recorded for the three and nine months ended September 30, 2015 and 2014.

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. 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.

As a result of its goodwill impairment evaluation at December 31, 2014, the Partnership recognized an $18.1 million non-cash impairment charge within asset impairments on its consolidated statement of operations for the year ended December 31, 2014. The goodwill impairment resulted from the reduction in the Partnership's estimated fair value of its gas and oil production reporting unit in comparison to its carrying amount at December 31, 2014. The Partnership's estimated fair value of its gas and oil production reporting unit was impacted by a decline in overall commodity prices during the fourth quarter of 2014.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates (see Note 8). The derivative instruments recorded in the consolidated balance sheets were measured as either an asset or liability at fair value. Changes in a derivative instrument's fair value are recognized currently in the Partnership's consolidated statements of operations unless specific hedge accounting criteria are met. On January 1, 2015, the Partnership discontinued hedge accounting through de-designation for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value after December 31, 2014 of these derivatives are recognized immediately within gain (loss) on mark-to-market derivatives in the Partnership's consolidated statements of operations, while the fair values of the instruments recorded in accumulated other comprehensive income as of December 31, 2014 will be reclassified to the consolidated statements of operations in the periods in which those respective derivative contracts settle. Prior to discontinuance of hedge accounting, the fair value of these commodity derivative instruments was recognized in accumulated other comprehensive income (loss) within partners' capital on the Partnership's consolidated balance sheets and reclassified to the Partnership's consolidated statements of operations at the time the originally hedged physical transactions affected earnings.

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.

Partnership Preferred Units

The following is a summary of recent Partnership Preferred Unit activity:

- In connection with the Partnership's acquisition of Titan Operating, L.L.C. in July 2012, the Partnership issued 3.8 million convertible Class B Partnership preferred units ("Class B Preferred Units"). While outstanding, the Class B Preferred Units received quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

  - On December 23, 2014, 3,796,900 of Class B Preferred Units were voluntarily converted into common units, while the remaining 39,654 Class B Preferred Units were converted into common units on July 25, 2015.

- In connection with the Partnership's acquisition of certain proved reserves and associated assets from EP Energy, Inc. in July 2013, the Partnership issued 3.7 million convertible Class C Partnership Preferred Units to Atlas Energy ("Class C Preferred Units"). The Class C Preferred Units receive quarterly cash distributions equal to the greater of (i) $0.51 and (ii) the quarterly common unit distribution.

- In October 2014, in connection with the Partnership's acquisition of assets in the Eagle Ford Shale (see Note 3), the Partnership issued 3.2 million of its 8.625% Class D cumulative redeemable perpetual preferred units ("Class D Preferred Units") and in March 2015, issued an additional 800,000 Class D Preferred Units (see Note 12). The Partnership pays quarterly distributions on the Class D Preferred Units at an annual rate of $2.15625 per unit, or 8.625% of the $25.00 liquidation preference.

- In April 2015, the Partnership issued 255,000 of its 10.75% Class E cumulative redeemable perpetual preferred units ("Class E Preferred Units"). The initial quarterly distribution on the Class E Preferred Units was $0.6793 per unit, representing the distribution for the period from April 14, 2015 through July 15, 2015. Subsequent to July 15, 2015, the Partnership pays future quarterly distributions on the Class E Preferred Units at an annual rate of $2.6875 per unit, or 10.75% of the liquidation preference.

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 and nine months ended September 30, 2015 and 2014.

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 2011. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of

September 30, 2015.

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 income (loss) allocated to the common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$(560,854)	$1,885	$(520,092)	$(27,558)
Preferred limited partner dividends	(4,293)	(4,475)	(12,180)	(13,298)
Net loss attributable to common limited partners and the general partner	(565,147)	(2,590)	(532,272)	(40,856)
Less: General partner's interest	11,303	(3,009)	10,645	(7,427)
Net loss attributable to common limited partners	(553,844)	(5,599)	(521,627)	(48,283)
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 - Basic	(553,844)	(5,599)	(521,627)	(48,283)
Plus: Convertible preferred limited partner dividends[(1)]	—	—	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Diluted	$(553,844)	$(5,599)	$(521,627)	$(48,283)

(1) Net income (loss) 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 and nine months ended September 30, 2015, net loss attributable to common limited partners' ownership interest is not allocated to approximately 346,000

and 501,000 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. For the three and nine months ended September 30, 2014, net loss attributable to common limited partners' ownership interest is not allocated to approximately 797,000 and 780,000 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. For the three and nine months ended September 30, 2015 and 2014, distributions on the Partnership's Class B and Class C preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

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 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 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Weighted average number of common limited partner units—basic	96,660	81,521	90,943	72,288
Add effect of dilutive incentive awards(1)	—	—	—	—
Add effect of dilutive convertible preferred limited partner units(2)	—	—	—	—
Weighted average number of common limited partner units—diluted	96,660	81,521	90,943	72,288

(1) For the three and nine months ended September 30, 2015, 346,000 and 501,000 phantom 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. For the three and nine months ended September 30, 2014, approximately 797,000 and 780,000 phantom 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 and nine months ended September 30, 2014 and the three and nine months ended September 30, 2015, 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 and nine months ended September 30, 2014 and the three and nine months ended September 30, 2015, potential common limited partner units issuable upon (a) conversion of the Partnership's 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.

Revenue Recognition

Natural gas and oil production. 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.

Drilling Partnerships. Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by the Partnership is deployed to drill and complete wells included within the partnership. As the Partnership deploys Drilling Partnership investor capital, it recognizes certain management fees it is entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if the Partnership has Drilling Partnership investor capital that has not yet been deployed, it will recognize a current liability titled "Liabilities Associated with Drilling Contracts" on the Partnership's consolidated balance sheets. After the Drilling Partnership well is completed and turned in line (i.e. wells that have been drilled, completed, and connected to a gathering system), the Partnership is entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees it is entitled to receive for services provided, the Partnership is also entitled to its pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%. The Partnership recognizes its Drilling Partnership management fees in the following manner:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, the Partnership receives a 15% mark-up on those costs incurred to drill and complete wells included within the partnership. Such fees are earned, in accordance with each Drilling Partnership's partnership agreement, and recognized as the services are performed, typically between 60 and 270 days.
- Administration and oversight. For each well drilled by a Drilling Partnership, the Partnership receives a fixed fee between $100,000 and $500,000, depending on the type of well drilled, which is earned in accordance with each Drilling Partnership's partnership agreement and recognized at the initiation of the well. Additionally, the

Drilling Partnership pays the Partnership a monthly per well administrative fee of $75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed.

- Well services. Each Drilling Partnership pays the Partnership a monthly per well operating fee, currently $1,000 to $2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed.

While the historical structure has varied, the Partnership has generally agreed to subordinate a portion of its share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of cumulative 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. The Partnership periodically compares 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, the Partnership recognizes subordination as an estimated reduction of its 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 the Partnership has 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, the Partnership will recognize an estimated increase in its portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

Gathering and processing revenue. 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 and the Chattanooga Shales. 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 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%.

The Partnership’s gas and oil production operations accrue 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 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 September 30, 2015 and December 31, 2014 of $46.3 million and $84.7 million, respectively, which were included in accounts receivable within the Partnership’s consolidated balance sheets.

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 for all periods presented, 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 Issued Accounting Standards

In September 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-16, Business Combinations (Subtopic 805) ("Update 2015-16")which eliminates the need to retrospectively adjust previously issued financial statements for changes in provisional amounts recognized at the date on which a business was acquired and later revised based on new information about facts and circumstances that existed at the acquisition date. Subsequent to the effective date of this accounting standard, such adjustments will be applied prospectively and the nature of, and reason for, the change in accounting principle will be disclosed. The Partnership will adopt the requirements of Update 2015-16 upon its effective date of January 1, 2016, and the Partnership does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In August 2015, the FASB issued ASU 2015-15, Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements which was a clarification of its previously issued ASU 2015-03, Interest—Imputation of Interest ("Update 2015-15")requiring entities to present debt issuance costs related to a recognized debt liability as a direct deduction from the carrying amount of that debt liability. Given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to line-of-credit arrangements, ASU 2015-15 effectively allows an entity to defer line-of-credit issuance costs and present such costs as an asset. These deferred debt issuance costs may be amortized ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Partnership will adopt the requirements of Update 2015-15 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In April 2015, the FASB issued ASU 2015-06, Earnings Per Share (Topic 260): Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions ("Update 2015-06"). Under Topic 260, Earnings per Share, master limited partnerships ("MLPs") apply the two-class method to calculate earnings per unit ("EPU") because the general partner, limited partners, and incentive distribution rights holders each participate differently in the distribution of available cash. When a general partner transfers (or "drops down") net assets to an MLP and that transaction is accounted for as a transaction between entities under common control, the statements of operations of the MLP are adjusted retrospectively to reflect the drop down transaction as if it occurred on the earliest date during which the entities were under common control. The amendments in Update 2015-06 specify that for purposes of calculating historical EPU under the two-class method, the earnings (losses) of a transferred business before the date of a drop down transaction should be allocated entirely to the general partner interest, and previously reported EPU of the limited partners would not change as a result of a drop down transaction. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the drop down transaction occurs also are required. The amendments in Update 2015-06 are effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted and amendments in Update 2015-06 should be applied retrospectively for all financial statements presented. The Partnership will adopt the requirements of Update 2015-06 upon its effective date of January 1, 2016, and the Partnership does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In March 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30) ("Update 2015-03"). The amendments in Update 2015-03 are intended to simplify presentation of debt issuance costs and require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs would not be affected by the amendments in Update 2015-03. The amendments in Update 2015-03 are effective for periods beginning after December 15, 2015, and interim periods within those periods. Early adoption is permitted, including adoption in an interim period, and an entity should apply the new guidance on a retrospective basis. The Partnership will adopt the requirements of Update 2015-03 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis ("Update 2015-02"). The amendments in Update 2015-02 are intended to improve targeted areas of consolidation guidance for legal entities such as limited partnerships, limited liability corporations and securitization structures. The amendments simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. The amendments in Update 2015-02 are effective for periods beginning after December 31, 2015. Early adoption is permitted, including adoption in an interim period. The Partnership will adopt the requirements of Update 2015-02 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In January 2015, the FASB issued ASU 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items ("Update 2015-01"). The amendments in Update 2015-01 simplify the income statement presentation requirements in Subtopic 225-20 by eliminating the concept of extraordinary items. Extraordinary items are events and transactions that are distinguished by their unusual nature and by the infrequency of their occurrence. The amendments in Update 2015-01 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. A reporting entity may apply the amendments prospectively. A reporting entity may also apply the amendments retrospectively to all prior periods presented in the financial statements. Early adoption is permitted provided that the guidance is applied from the beginning of the fiscal year of adoption. The Partnership will adopt the requirements of Update 2015-01 upon its effective date of January 1, 2016, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In November 2014, the FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815) – Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity ("Update 2014-16"). Certain classes of shares include features that entitle the holders to preferences and rights (such as conversion rights, redemption rights, voting powers, and liquidation and dividend payment preferences) over the other shareholders. Shares that include embedded derivative features are referred to as hybrid financial instruments, which must be separated from the host contract and accounted for as a derivative if certain criteria are met under Subtopic 815-10. One criterion requires evaluating whether the nature of the host contract is more akin to debt or to equity and whether the economic characteristics and risks of the embedded derivative feature are "clearly and closely related" to the host contract. In making that evaluation, an issuer or investor may consider all terms and features in a hybrid financial instrument including the embedded derivative feature that is being evaluated for separate accounting or may consider all terms and features in the hybrid financial instrument except for the embedded derivative feature that is being evaluated for separate accounting. The use of different methods can result in different accounting outcomes for economically similar hybrid financial instruments. Additionally, there is diversity in practice with respect to the consideration of redemption features in relation to other features when determining whether the nature of a host contract is more akin to debt or to equity. The amendments in Update 2014-16 clarify how current U.S. GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. The effects of initially adopting the amendments in Update 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in the form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. The amendments in Update 2014-16 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption, including adoption in an interim period, is permitted. The Partnership will adopt the requirements of Update 2014-16 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40) ("Update 2014-15"). The amendments in Update 2014-15 provide U.S. GAAP guidance on the responsibility of an entity's management in evaluating whether there is substantial doubt about the entity's ability to continue as a going concern and about related footnote disclosures. For each reporting period, an entity's management will be required 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. In doing so, the amendments in Update 2014-15 should reduce diversity in the timing and content of footnote disclosures. The amendments in Update 2014-15 are effective for the annual period ending after December 15, 2016, and for annual and interim periods thereafter. Early adoption is permitted. The Partnership will adopt the requirements of Update 2014-15 upon its effective date in 2016, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In June 2014, the FASB issued ASU 2014-12, Compensation – Stock Compensation (Topic 718) ("Update 2014-12"). The amendments in Update 2014-12 require that a performance target that affects vesting and that could be achieved after the requisite service period, be treated as a performance condition. As such, the performance target should not be reflected in estimating the grant date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. The amendments in Update 2014-12 are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption is permitted. Entities may apply the amendments in

Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The Partnership will adopt the requirements of Update 2014-12 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, Property, Plant and Equipment, and intangible assets within the scope of Topic 350, Intangibles – Goodwill and Other) are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is not permitted. The Partnership will adopt the requirements of Update 2014-09 retrospectively upon its effective date of January 1, 2018, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

NOTE 3 – ACQUISITIONS

Rangely Acquisition

On June 30, 2014, the Partnership completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado from Merit Management Partners I, L.P., Merit Energy Partners III, L.P. and Merit Energy Company, LLC (collectively, "Merit Energy") for approximately $408.9 million in cash, net of purchase price adjustments (the "Rangely Acquisition"). The purchase price was funded through borrowings under the Partnership's revolving credit facility, the issuance of an additional $100.0 million of its 7.75% senior notes due 2021 ("7.75% Senior Notes") (see Note 7) and the issuance of 15,525,000 common limited partner units (see Note 12). The Rangely Acquisition had an effective date of April 1, 2014. The Partnership's consolidated financial statements reflected the operating results of the acquired business commencing June 30, 2014 with the transaction closing.

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 $11.6 million of transaction fees, which were included with common limited partners' interests for the year ended December 31, 2014 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

The following table presents the 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	$4,041
Property, plant and equipment	405,416
Other assets, net	2,888
Total assets acquired	$412,345
Liabilities:	
Accrued liabilities	2,117
Asset retirement obligation	1,305
Total liabilities assumed	3,422

Net assets acquired	$408,923

Other Acquisitions

Arkoma Acquisition

On June 5, 2015, the Partnership completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). The Partnership funded the purchase price through the issuance of 6,500,000 common limited partner units (see Note 12). The Arkoma Acquisition had an effective date of January 1, 2015. The Partnership accounted for the Arkoma Acquisition as a transaction between entities under common control (see Note 2).

Eagle Ford Acquisition

On November 5, 2014, the Partnership and AGP completed an acquisition of oil and natural gas liquid interests in the Eagle Ford Shale in Atascosa County, Texas from Cima Resources, LLC and Cinco Resources, Inc. (together "Cinco") for $342.0 million, net of purchase price adjustments (the "Eagle Ford Acquisition"). Approximately $183.1 million was paid in cash by the Partnership and $19.9 million was paid by AGP at closing, and approximately $139.0 million was to be paid in four quarterly installments beginning December 31, 2014. On December 31, 2014, AGP made its first installment payment of $35.0 million related to its Eagle Ford Acquisition. Prior to the March 31, 2015 installment, the Partnership, AGP, and Cinco amended the purchase and sale agreement to alter the timing and amount of the quarterly payments beginning with the March 31, 2015 payment and ending December 31, 2015, with no change to the overall purchase price. On March 31, 2015, AGP paid $28.3 million and the Partnership issued $20.0 million of its Class D Preferred Units (see Note 12) to satisfy the second installment related to the Eagle Ford Acquisition. On June 30, 2015, AGP paid $16.0 million and the Partnership paid $0.6 million to satisfy the third installment related to the Eagle Ford Acquisition. In September 2015, the Partnership agreed with AGP to have AGP transfer its remaining $36.3 million of deferred purchase obligation, along with the related undeveloped natural gas and oil properties, to the Partnership. On September 30, 2015 the Partnership paid $17.5 million to satisfy the fourth installment related to the Eagle Ford Acquisition. At September 30, 2015, the Partnership's remaining deferred portion of the purchase price was $21.6 million, payable on December 31, 2015. The Partnership's issuance of Class D Preferred Units represents a non-cash transaction for statement of cash flow purposes during the nine months ended September 30, 2015.

GeoMet Acquisition

On May 12, 2014, the Partnership completed the acquisition of certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for approximately $97.9 million in cash, net of purchase price adjustments, with an effective date of January 1, 2014. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2015	December 31, 2014	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$ 456,181	$ 441,548	
Pre-development costs	8,167	7,223	
Wells and related equipment	3,081,614	3,026,416	
Total proved properties	3,545,962	3,475,187	
Unproved properties	264,844	217,321	
Support equipment	44,260	37,359	
Total natural gas and oil properties	3,855,066	3,729,867	
Pipelines, processing and compression facilities	56,632	49,547	2 – 40
Rights of way	829	830	20 – 40
Land, buildings and improvements	9,202	9,160	3 – 40
Other	18,316	17,936	3 – 10
	3,940,045	3,807,340	
Less – accumulated depreciation, depletion and amortization	(2,405,327)	(1,543,520)	
	$ 1,534,718	$ 2,263,820	

During the three and nine months ended September 30, 2015, the Partnership recognized a $0.4 million and a $0.3 million loss, respectively, on asset sales and disposals. During the nine months ended September 30, 2014, the Partnership recognized $1.7 million of loss on asset sales and disposals primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement.

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. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2015 and 2014.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. For the three and nine months ended September 30, 2015, the Partnership recognized $740.2 million of asset impairment related to oil and gas properties in the Barnett, Coal-bed Methane, Southern

Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, reduced by $68.0 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairment and the related hedge gains are included in Asset impairment expense in the Partnership's combined consolidated results of operations. There were no impairments of proved gas and oil properties for the three and nine months ended September 30, 2014.

During the nine months ended September 30, 2015 and 2014, the Partnership recognized $5.2 million and $42.5 million, respectively, of non-cash property, plant and equipment additions, which were included within the changes in accounts payable and accrued liabilities on the Partnership's consolidated statements of cash flows.

NOTE 5 – OTHER ASSETS

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

	September 30, 2015	December 31, 2014
Deferred financing costs, net of accumulated amortization of $31,774 and $18,622 at September 30, 2015 and December 31, 2014, respectively	$ 44,571	$ 40,637
Notes receivable	3,871	3,866
Other	5,384	5,578
	$ 53,826	$ 50,081

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 $3.2 million and $2.4 million for the three months ended September 30, 2015 and 2014, respectively, and $8.9 million and $6.1 million for the nine months ended September 30, 2015 and 2014, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the nine months ended September 30, 2015, the Partnership recognized $4.3 million for accelerated amortization of deferred financing costs associated with a reduction of the borrowing base under the revolving credit facility. There was no accelerated amortization of deferred financing costs for the Partnership during the three months ended September 30, 2015 and 2014 and the nine months ended September 30, 2014.

At September 30, 2015 and December 31, 2014, 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 September 30, 2015 and 2014, approximately $21,000 and $22,000, respectively, of interest income was recognized within other, net on the Partnership's consolidated statements of operations, and approximately $64,000 and $68,000 for the nine months ended September 30, 2015 and 2014, respectively. At September 30, 2015 and December 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 where 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, the 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 September 30, 2015, the Drilling Partnerships had $45.6 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. As of September 30, 2015, the Partnership has withheld $4.3 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Asset retirement obligations, beginning of period	$110,775	$101,325	$107,950	$91,179
Liabilities incurred	80	323	292	8,178
Liabilities settled	(1)	(271)	(547)	(820)
Accretion expense	1,581	1,468	4,740	4,308
Asset retirement obligations, end of period	$112,435	$102,845	$112,435	$102,845

The above accretion expense was included in depreciation, depletion and amortization in the Partnership's consolidated statements of operations. During the year ended December 31, 2014, the Partnership incurred $7.0 million of future plugging and abandonment costs related to acquisitions it consummated (see Note 3). During the nine months ended September 30, 2014, the Partnership incurred $6.6 million of future plugging and abandonment liabilities within purchase accounting for the Rangely and GeoMet acquisitions it consummated during the period (see Note 3). No future plugging and abandonment liabilities related to consummated acquisitions were incurred during the three and nine months ended September 30, 2015.

NOTE 7 - DEBT

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

	September 30, 2015	December 31, 2014
Revolving credit facility	$563,000	$696,000
Term loan facility	243,408	—
7.75 % Senior Notes – due 2021	374,601	374,544
9.25 % Senior Notes – due 2021	324,038	323,916
Total debt	1,505,047	1,394,460
Less current maturities	—	—
Total long-term debt	$1,505,047	$1,394,460

Credit Facility

The Partnership is a party to its Second Amended and Restated Credit Agreement dated July 31, 2013, as amended, with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the "Credit Agreement"), which provides for a senior secured revolving credit facility with a borrowing base of $750.0 million as of September 30, 2015.

The Partnership's borrowing base is scheduled for semi-annual redeterminations in November 2015 and thereafter in May and November of each year. In July 2015, a determination by the lenders reaffirmed the Partnership's $750.0 million borrowing base. The Credit Agreement also provides that the Partnership's borrowing base will be reduced by 25% of the stated amount of any senior notes issued, or additional second lien debt incurred, after July 1, 2015. At September 30, 2015, $563.0 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 $4.3 million was outstanding at September 30, 2015. 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 1.50% 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 0.50% and 1.75% per annum. If the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, the applicable margin on Eurodollar loans and ABR loans will be increased by 0.25%. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At September 30, 2015, the weighted average interest rate on outstanding borrowings under the credit facility was 2.75%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness (excluding second lien debt in an aggregate principal amount of up to $300.0 million), 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 September 30, 2015. 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 (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter 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 September 30, 2015, the Partnership's ratio of current assets to current liabilities was 1.4 to 1.0, and its ratio of Total Funded Debt to EBITDA was 5.2 to 1.0.

Term Loan Facility

On February 23, 2015, the Partnership entered into a Second Lien Credit Agreement with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"). The Term Loan Facility matures on February 23, 2020. The Term Loan Facility is presented net of unamortized discount of $6.6 million at September 30, 2015.

The Partnership has the option to prepay the Term Loan Facility at any time, and is required to offer to prepay the Term Loan Facility with 100% of the net cash proceeds from the issuance or incurrence of any debt and 100% of the excess net cash proceeds from certain asset sales and condemnation recoveries. The Partnership is also required to offer to prepay the Term Loan Facility upon the occurrence of a change of control. All prepayments are subject to the following premiums, plus accrued and unpaid interest:

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;

- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

The Partnership's obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of its assets and those of its restricted subsidiaries (the "Loan Parties") that guarantee the Partnership's existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by the Partnership's material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at the Partnership's option, at either

(i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the applicable maturity date for Eurodollar loans and quarterly for ABR loans. At September 30, 2015, the weighted average interest rate on outstanding borrowings under the term loan facility was 10.0%.

The Second Lien Credit Agreement contains customary covenants that limit the Partnership's 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 Second Lien Credit Agreement contains covenants substantially similar to those in the Partnership's existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. The Partnership was in compliance with these covenants as of September 30, 2015.

Under the Second Lien Credit Agreement, the Partnership may elect to add one or more incremental term loan tranches to the Term Loan Facility so long as the aggregate outstanding principal amount of the Term Loan Facility plus the principal amount of any incremental term loan does not exceed $300.0 million and certain other conditions are adhered to. Any such incremental term loans may not mature on a date earlier than February 23, 2020.

Senior Notes

At September 30, 2015, the Partnership had $374.6 million outstanding of its 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 September 30, 2015. 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 for 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 Partnership may redeem the 7.75% Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (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. 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 7.75% Senior Notes.

At September 30, 2015, the Partnership had $324.0 million outstanding of its 9.25% senior unsecured notes due 2021 ("9.25% Senior Notes"). The 9.25% Senior Notes were presented net of a $1.0 million unamortized discount as of September 30, 2015. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time prior to August 15, 2017, the Partnership may redeem the 9.25% Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid interest, if any. 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%. 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.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of the Partnership's material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% 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 7.75% Senior Notes and 9.25% 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 September 30, 2015.

Total cash payments for interest by the Partnership were $87.7 million and $55.2 million for the nine months ended September 30, 2015 and 2014, 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 the New York Mercantile Stock Exchange (“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.

On January 1, 2015, the Partnership discontinued hedge accounting for its qualified commodity derivatives. As such, changes in fair value of these derivatives after December 31, 2014 are recognized immediately within gain (loss) on mark-to-market derivatives in the Partnership’s consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners’ capital on the Partnership’s consolidated balance sheet, are being reclassified to the Partnership’s consolidated statements of operations at the time the originally hedged physical transactions settle.

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 recorded net derivative assets of $352.6 million and $274.9 million on its consolidated balance sheets at September 30, 2015 and December 31, 2014, respectively. Of the $46.4 million of deferred gains in accumulated other comprehensive income on the Partnership’s consolidated balance sheet at September 30, 2015, the Partnership will reclassify $27.7 million of gains to its consolidated statement of operations over the next twelve month period as these contracts expire with the remaining gains of $18.7 million being reclassified to the Partnership’s consolidated statements of operations in later periods as the remaining contracts expire.

The following table summarizes the commodity derivative activity for the three and nine months ended September 30, 2015 (in thousands):

	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
	$ (23,927)	$ (77,048)

Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets[1]		
Portion of settlements attributable to subsequent mark to market gains	(19,555)	(49,680)
Total cash settlements on commodity derivative contracts	(43,482)	(126,728)
2015 Unrealized gains prior to settlement[2]	10,426	17,259
Unrealized gain on open derivative contracts at September 30, 2015, net of amounts recognized in income in prior year[2]	120,639	192,447
Gains on mark-to-market derivatives	$ 131,065	$ 209,706

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

The Partnership had gains of $43.5 million and $1.4 million related to cash settlements during the three months ended September 30, 2015 and 2014, respectively, and a gain of $126.7 million and a loss of $22.7 million related to cash settlements during the nine months ended September 30, 2015 and 2014, respectively. 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 and nine months ended September 30, 2015 and 2014 for hedge ineffectiveness.

The following table summarizes the gross fair values of the Partnership's derivative instruments, presenting the impact of offsetting the derivative assets and liabilities included 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 September 30, 2015			
Current portion of derivative assets	$ 146,629	$ (7)	$ 146,622
Long-term portion of derivative assets	205,979	—	205,979
Total derivative assets	$ 352,608	$ (7)	$ 352,601
As of December 31, 2014			
Current portion of derivative assets	$ 144,357	$ (98)	$ 144,259
Long-term portion of derivative assets	130,972	(370)	130,602
Total derivative assets	$ 275,329	$ (468)	$ 274,861

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 September 30, 2015			
Current portion of derivative liabilities	$ (7)	$ 7	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ (7)	$ 7	$ —
As of December 31, 2014			
Current portion of derivative liabilities	$ (98)	$ 98	$ —
Long-term portion of derivative liabilities	(370)	370	—
Total derivative liabilities	$ (468)	$ 468	$ —

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 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.

At September 30, 2015, 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 (in thousands)(2)
2015	13,611,100	$ 4.193	$ 21,734
2016	53,546,300	$ 4.229	75,852
2017	49,920,000	$ 4.219	60,364
2018	40,800,000	$ 4.170	44,298
2019	15,960,000	$ 4.017	13,785
			$ 216,033

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)	Fair Value Asset (in thousands)(2)
2015	Puts purchased	600,000	$ 3.934	$ 803
2015	Calls sold	600,000	$ 4.634	—
				$ 803

Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes	Average Fixed Price