

Atlas Resource Partners, L.P.
Form 10-Q
November 08, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

OR

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

For the transition period from _____ to _____

Commission file number: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware 45-3591625
(State or other jurisdiction of incorporation or organization) (I.R.S. Employer Identification No.)

Park Place Corporate Center One
1000 Commerce Drive, Suite 400
Pittsburgh, Pennsylvania 15275
(Address of principal executive office) (Zip code)

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

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

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

Large accelerated filer Accelerated filer
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

The number of outstanding common limited partner units of the registrant on November 4, 2013 was 59,447,058.

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)

ASSETS	September 30, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	\$ 1,452	\$ 23,188
Accounts receivable	59,669	38,718
Current portion of derivative asset	19,474	12,274
Subscriptions receivable	13,900	55,357
Prepaid expenses and other	11,610	9,063
Total current assets	106,105	138,600
Property, plant and equipment, net	2,175,754	1,302,228
Goodwill and intangible assets, net	32,843	33,104
Long-term derivative asset	28,500	8,898
Long-term derivative asset receivable from Drilling Partnerships	182	
Other assets, net	43,468	16,122
	\$ 2,386,852	\$ 1,498,952
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable	\$ 74,686	\$ 59,549
Advances from affiliates	23,559	5,853
Liabilities associated with drilling contracts		67,293
Current portion of derivative liability	318	
Current portion of derivative payable to Drilling Partnerships	4,932	11,293
Accrued well drilling and completion costs	47,149	47,637
Accrued liabilities	33,873	25,388
Total current liabilities	184,517	217,013
Long-term debt	948,279	351,425
Long-term derivative liability		888
Long-term derivative payable to Drilling Partnerships		2,429
Asset retirement obligations and other	84,127	65,191
Commitments and contingencies		
Partners Capital:		
General partner's interest	5,716	7,029
Preferred limited partners' interests	183,325	96,155

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Class C preferred limited partner warrants	1,176	
Common limited partners interests	929,474	737,253
Accumulated other comprehensive income	50,238	21,569
Total partners capital	1,169,929	862,006
	\$ 2,386,852	\$ 1,498,952

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,	
	2013	2012	2013	2012
Revenues:				
Gas and oil production	\$ 80,332	\$ 24,699	\$ 173,490	\$ 61,323
Well construction and completion	10,964	36,317	92,293	92,277
Gathering and processing	3,591	4,134	11,639	10,311
Administration and oversight	4,447	4,440	8,923	8,586
Well services	5,023	5,086	14,703	15,344
Other, net	(13,272)	67	(14,589)	(4,952)
Total revenues	91,085	74,743	286,459	182,889
Costs and expenses:				
Gas and oil production	29,419	7,295	63,670	16,247
Well construction and completion	9,534	31,581	80,255	79,882
Gathering and processing	4,395	4,558	13,767	13,185
Well services	2,386	2,232	7,009	7,076
General and administrative	31,983	16,147	63,767	48,427
Chevron transaction expense		7,670		7,670
Depreciation, depletion and amortization	41,656	13,918	85,061	33,848
Total costs and expenses	119,373	83,401	313,529	206,335
Operating loss	(28,288)	(8,658)	(27,070)	(23,446)
Interest expense	(10,748)	(1,423)	(22,145)	(2,529)
Gain (loss) on asset sales and disposal	(661)	2	(2,035)	(7,019)
Net loss	(39,697)	(10,079)	(51,250)	(32,994)
Preferred limited partner dividends	(3,564)	(1,221)	(7,592)	(1,221)
Net loss attributable to owner's interest, common limited partners and the general partner	\$ (43,261)	\$ (11,300)	\$ (58,842)	\$ (34,215)
Allocation of net income (loss):				
Portion applicable to owner's interest (period prior to the transfer of assets on March 5, 2012)	\$	\$	\$	\$ 250
Portion applicable to common limited partners and the general partner's interests (period subsequent to the transfer of assets on March 5, 2012)	(43,261)	(11,300)	(58,842)	(34,465)
Net loss attributable to owner's interest, common limited partners and the general partner	\$ (43,261)	\$ (11,300)	\$ (58,842)	\$ (34,215)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	\$ (44,073)	\$ (11,074)	\$ (60,977)	\$ (33,776)

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General partner's interest	812	(226)	2,135	(689)
Net loss attributable to common limited partners and the general partner	\$ (43,261)	\$ (11,300)	\$ (58,842)	\$ (34,465)
Net loss attributable to common limited partners per unit:				
Basic and Diluted	\$ (0.74)	\$ (0.32)	\$ (1.21)	\$ (1.06)
Weighted average common limited partner units outstanding:				
Basic and Diluted	59,440	35,068	50,197	31,865

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,	
	2013	2012	2013	2012
Net loss	\$ (39,697)	\$ (10,079)	\$ (51,250)	\$ (32,994)
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	15,064	(19,487)	33,093	(5,832)
Less: reclassification adjustment for realized gains of cash flow hedges in net loss	(1,145)	(6,114)	(4,424)	(15,453)
Total other comprehensive income (loss)	13,919	(25,601)	28,669	(21,285)
Comprehensive loss attributable to owner's interest, common and preferred limited partners and the general partner	\$ (25,778)	\$ (35,680)	\$ (22,581)	\$ (54,279)

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in thousands, except unit data)

(Unaudited)

General Interest	Class B		Preferred Limited Partners Interest		Class C Limited Partners Interests		Common Limited Partners Interests		Class C Preferred Limited Partner Warrants	
	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units
\$ 7,029	3,836,554	\$ 96,155	3,749,986	\$ 85,448	43,973,153	\$ 737,253				
					15,259,174	320,092	562,497	1,176		
						212,331				
							10,199			
(3,448)		(5,870)					(75,632)			
							(1,461)			
2,135		6,177		1,415		(60,977)				
			3,749,986	\$ 86,863						\$
\$ 5,716	3,836,554	\$ 96,462			59,444,658	\$ 929,474	562,497	1,176		

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	\$ (51,250)	\$ (32,994)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	85,061	33,848
Non-cash gain on derivative value, net	(7,675)	(17,013)
Loss on asset sales and disposal	2,035	7,019
Non-cash compensation expense	10,209	7,856
Amortization of deferred financing costs	8,608	1,028
Changes in operating assets and liabilities:		
Accounts receivable and prepaid expenses and other	35,665	16,105
Accounts payable and accrued liabilities	(69,463)	(30,836)
Net cash provided by (used in) operating activities	13,190	(14,987)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(203,996)	(73,379)
Net cash paid for acquisitions	(712,984)	(264,558)
Other	(5,676)	69
Net cash used in investing activities	(922,656)	(337,868)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	752,000	264,000
Repayments under credit facilities	(678,425)	(42,000)
Net proceeds from issuance of long-term debt	510,518	
Net investment from owners		5,625
Distributions paid to unit holders	(84,950)	(16,362)
Net proceeds from issuance of Class C preferred limited partner units and warrants	86,624	
Net proceeds from issuance of common limited partner units	320,092	119,389
Deferred financing costs, distribution equivalent rights and other	(18,129)	(8,239)
Net cash provided by financing activities	887,730	322,413
Net change in cash and cash equivalents	(21,736)	(30,442)
Cash and cash equivalents, beginning of year	23,188	54,708
Cash and cash equivalents, end of period	\$ 1,452	\$ 24,266

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2013

(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the Partnership) is a publicly traded Delaware master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas, crude oil and natural gas liquids (NGL) with operations in basins across the United States. The Partnership sponsors and manages tax-advantaged investment partnerships, in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities. At September 30, 2013, Atlas Energy, L.P. (ATLS), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of the general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 36.9% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

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

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2012 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, 2012. 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, 2013 may not necessarily be indicative of the results of operations for the full year ending December 31, 2013.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Combination

The Partnership's consolidated balance sheets at September 30, 2013 and December 31, 2012, the consolidated statements of operations for the three months ended September 30, 2013 and 2012, the consolidated statements of operations for the nine months ended September 30, 2013, and the portion of the consolidated statement of operations for the nine months ended September 30, 2012 subsequent to the transfer of assets on March 5, 2012 include the accounts of the Partnership and its wholly-owned subsidiaries. The portion of the consolidated statement of operations for the nine months ended September 30, 2012 prior to the transfer of assets on March 5, 2012 was derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if the Partnership had been operated as an unaffiliated entity. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management's best estimates, in order to derive the financial statements of the Partnership for the periods presented prior to March 5, 2012. Actual balances and results could be different from those estimates. Transactions between the Partnership and other ATLS operations have been identified in the consolidated statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

In accordance with established practice in the oil and gas industry, the Partnership's consolidated financial statements include its pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the energy partnerships in which the Partnership has an interest (the Drilling Partnerships). Such interests typically range from 20% to 41%. The Partnership's consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, the Partnership calculates these items specific to its own economics as further explained under the heading Property, Plant and Equipment elsewhere within this note.

Use of Estimates

The preparation of the Partnership's consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership's consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired and liabilities assumed. Such estimates included estimated allocations made from the historical accounting records of ATLS in order to derive the historical financial statements of the Partnership for periods prior to March 5, 2012. 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, 2013 and 2012 represent actual results in all material respects (see Revenue Recognition).

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. In evaluating the realizability of its accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by management's review of the Partnership's customers' credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At September 30, 2013 and December 31, 2012, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had \$5.3 million of inventory at September 30, 2013 and December 31, 2012, which was included within prepaid expenses and other current assets on the Partnership's consolidated balance sheets. The Partnership values inventories at the lower of cost or market. The Partnership's inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

Property, Plant and Equipment

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

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

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

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

Impairment of Long-Lived Assets

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

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

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, the Partnership's reserve estimates for its investment in the Drilling Partnerships are based on its own assumptions rather than its proportionate share of the limited partnerships' reserves. These assumptions include the Partnership's actual capital contributions, an additional carried interest (generally 5% to 10%), a disproportionate share of salvage value

upon plugging of the wells and lower operating and administrative costs.

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

The Partnership's method of calculating its reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships, which the Partnership sponsors and owns an interest in but does not control. The Partnership's reserve quantities include reserves in excess of its proportionate share of reserves in Drilling Partnerships, which the Partnership may be unable to recover due to the Drilling Partnerships' legal structure. The Partnership may have to pay additional consideration in the future as a well or Drilling Partnership becomes uneconomic under the terms of the Drilling Partnership's agreement in order to recover these excess reserves and to acquire any additional residual interests in the wells held by other partnership investors. The acquisition of any such uneconomic well interest from the Drilling Partnership by the Partnership is governed under the Drilling Partnership's agreement. In general, the

Partnership will seek consent from the Drilling Partnership's limited partners to acquire the well interests from the Drilling Partnership based upon the Partnership's determination of fair market value.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2013 and 2012.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2012, the Partnership recognized \$9.5 million of asset impairments related to gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of these gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2012. The estimate of the fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement. There were no impairments of proved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2013 and 2012.

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 6.3% and 3.1% for the three months ended September 30, 2013 and 2012, respectively, and 6.1% and 3.5% for the nine months ended September 30, 2013 and 2012, respectively. The aggregate amount of interest capitalized by the Partnership was \$3.6 million and \$0.6 million for the three months ended September 30, 2013 and 2012, respectively, and \$10.5 million and \$1.0 million for the nine months ended September 30, 2013 and 2012, respectively.

Intangible Assets

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

The following table reflects the components of intangible assets being amortized at September 30, 2013 and December 31, 2012 (in thousands):

	September 30, 2013	December 31, 2012	Estimated Useful Lives In Years
Gross Carrying Amount	\$ 14,344	\$ 14,344	13
Accumulated Amortization	(13,285)	(13,024)	
Net Carrying Amount	\$ 1,059	\$ 1,320	

Amortization expense on intangible assets was \$0.1 million and approximately \$45,000 for the three months ended September 30, 2013 and 2012, respectively, and \$0.3 million and \$0.1 million for the nine months ended September 30, 2013 and 2012, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2013 \$0.4 million; 2014 \$0.3 million; 2015 \$0.2 million; 2016 \$0.1 million and 2017 \$0.1 million.

Goodwill

At September 30, 2013 and December 31, 2012, the Partnership had \$31.8 million of goodwill recorded in connection with its prior consummated acquisitions. No changes in the carrying amount of goodwill were recorded for the three and nine months ended September 30, 2013 and 2012.

The Partnership tests goodwill for impairment at each year end by comparing its reporting units' estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership's management must

apply judgment in determining the estimated fair value of these reporting units. The Partnership's management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership's assets and the available market data of the industry group. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership's market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership's management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership's industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership's industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise. During the three and nine months ended September 30, 2013 and 2012, no impairment indicators arose, and no goodwill impairments were recognized by the Partnership.

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.

Asset Retirement Obligations

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

Income Taxes

The Partnership is not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership's taxable income. Such taxable income may vary substantially from net income reported in the accompanying consolidated financial statements. Certain corporate subsidiaries of the Partnership are subject to federal and state income tax. The federal and state income taxes related to

the Partnership and these corporate subsidiaries were immaterial to the consolidated financial statements and are recorded in pre-tax income on a current basis only. Accordingly, no federal or state deferred income tax has been provided for in the accompanying consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a more-likely-than-not threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the three and nine months ended September 30, 2013 and 2012.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of September 30, 2013.

Stock-Based Compensation

The Partnership recognizes all share-based payments to employees, including grants of employee stock options, in the consolidated financial statements based on their fair values (see Note 14).

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.

Prior to the transfer of assets to the Partnership on March 5, 2012 (see Note 1), the Partnership had no common units or General Partner Class A units outstanding. In addition, the Partnership had no net income (loss) attributable to common limited partners and the general partner prior to March 5, 2012.

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 loss attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Net loss	\$ (39,697)	\$ (10,079)	\$ (51,250)	\$ (32,994)
Income applicable to owner's interest (period prior to transfer of assets on March 5, 2012)				(250)
Preferred limited partner dividends	(3,564)	(1,221)	(7,592)	(1,221)
Net loss attributable to common limited partners and the general partner	(43,261)	(11,300)	(58,842)	(34,465)
Less: General partner's interest	(812)	226	(2,135)	689
Net loss attributable to common limited partners	(44,073)	(11,074)	(60,977)	(33,776)
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	\$ (44,073)	\$ (11,074)	\$ (60,977)	\$ (33,776)

⁽¹⁾ Net income attributable to common limited partners' ownership interests is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended September 30, 2013 and 2012, net loss attributable to common limited partners' ownership interest is not allocated to approximately 835,000 and 898,000 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 nine months ended September 30, 2013 and 2012, net loss attributable to common limited partners' ownership interest is not allocated to approximately 918,000 and 575,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, convertible preferred units and warrants, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership's long-term incentive plan (see Note 14).

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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		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Weighted average number of common limited partner units basic	59,440	35,068	50,197	31,865
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	59,440	35,068	50,197	31,865

⁽¹⁾ For the three months ended September 30, 2013 and 2012, approximately 835,000 units and 898,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the nine months ended September 30, 2013 and 2012, approximately 918,000 units and 575,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

⁽²⁾ For the three and nine months ended September 30, 2013 and 2012, potential common limited partner units issuable upon (a) conversion of the Partnership's Class B and Class C preferred units and (b) exercise of the warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

Revenue Recognition

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

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

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Partnership's records and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see *Use of Estimates* for further description). The Partnership had unbilled revenues at September 30, 2013 and December 31, 2012 of \$54.1 million and \$33.4 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 at September 30, 2013, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 8).

Recently Adopted Accounting Standards

In July 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2013-10, Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes (Update 2013-10), which amends Accounting Standards Codification Topic 815. Topic 815 provides guidance on the risks that are permitted to be hedged in a fair value or cash flow hedge. In addition, only the interest rates on direct Treasury obligations of the U.S. Government (UST) and the London Interbank Offered Rate (LIBOR) swap rate are considered benchmark interest rates. Update 2013-10 amends Topic 815 to include the Overnight Index Swap Rate (OIS), also referred to as the Fed Funds Effective Swap Rate, as a U.S. benchmark interest rate for hedge accounting purposes. Including the OIS as an acceptable U.S. benchmark interest rate in addition to UST and LIBOR will provide risk managers with a more comprehensive spectrum of interest rate resets to utilize as the designated benchmark interest rate risk component under the hedge accounting guidance in Topic 815. Update 2013-10 is effective for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. The Partnership adopted the requirements of Update 2013-10 upon its effective date of July 17, 2013, and it had no material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220) (Update 2013-02). Update 2013-02 requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present significant amounts reclassified out of accumulated other comprehensive income if the amount reclassified to net income in its entirety is in the same reporting period as incurred. For

other amounts that are not required to be reclassified in their entirety to net income, an entity is required to reference to other disclosures that provide additional detail about those amounts. Entities are required to implement the amendments prospectively for reporting periods beginning after December 15, 2012, with early adoption being permitted. The Partnership adopted the requirements of Update 2013-02 upon its effective date of January 1, 2013, and it had no material impact on its financial position, results of operations or related disclosures.

Recently Issued Accounting Standards

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (Update 2013-11), which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership will apply the requirements of Update 2013-11 upon its effective date of January 1, 2014, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (Update 2013-04). Update 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements, for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations and settled litigation and judicial rulings. Update 2013-04 requires an entity to measure joint and several liability arrangements, for which the total amount of the obligation is fixed at the reporting date as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, Update 2013-04 provides disclosure guidance on the nature and amount of the obligation as well as other information. Update 2013-04 is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. The Partnership will apply the requirements of Update 2013-04 upon its effective date of January 1, 2014, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

NOTE 3 ACQUISITIONS

EP Energy Acquisition

On July 31, 2013, the Partnership completed an acquisition of assets from EP Energy E&P Company, L.P. (EP Energy). Pursuant to the purchase and sale agreement, the Partnership acquired certain assets from EP Energy for approximately \$705.9 million in cash, net of purchase price adjustments (the EP Energy Acquisition). The purchase price was funded through borrowings under the Partnership s revolving credit facility, the issuance of the Partnership s 9.25% Senior Notes due August 15, 2021 (see Note 7), and the issuance of 14,950,000 common limited partner units and 3,749,986 newly created Class C convertible preferred units (see Note 12). The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013. The accompanying consolidated financial statements reflect the operating results of the acquired business commencing July 31, 2013.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). All costs associated with the acquisition of assets were expensed as incurred. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

Assets:

Property, plant and equipment \$ 720,118

Liabilities:

Asset retirement obligation 14,142

Net assets acquired \$ 705,976

Revenues and net loss of \$25.8 million and \$4.8 million, respectively, have been included in the Partnership's consolidated statements of operations related to the EP Energy Acquisition for the three and nine months ended September 30, 2013.

DTE Acquisition

On December 20, 2012, the Partnership completed the acquisition of DTE Gas Resources, LLC from DTE Energy Company (NYSE: DTE; DTE) for \$257.4 million, subject to certain post-closing adjustments (the DTE Acquisition). In connection with entering into a purchase agreement related to the DTE Acquisition, the Partnership issued approximately 7.9 million of its common limited partner units through a public offering in November 2012 for \$174.5 million, which was used to partially repay amounts outstanding under its revolving credit facility prior to closing (see Note 12). The cash paid at closing was funded through \$179.8 million of borrowings under the Partnership's revolving credit facility and \$77.6 million through borrowings under its term loan credit facility (see Note 7).

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). Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

Assets:	
Accounts receivable	\$ 10,721
Prepaid expenses and other	2,100
Total current assets	12,821
Property, plant and equipment	263,194
Other assets, net	273
Total assets acquired	\$ 276,288
Liabilities:	
Accounts payable	\$ 7,760
Accrued liabilities	2,910
Total current liabilities	10,670
Asset retirement obligation and other	8,169
Total liabilities assumed	18,839
Net assets acquired	\$ 257,449

Titan Acquisition

On July 25, 2012, the Partnership completed the acquisition of Titan Operating, L.L.C. (Titan) in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had an estimated collective value of \$193.2 million, based upon the closing price of the Partnership's publicly traded units as of the acquisition closing date), as well as \$15.4 million in cash for closing adjustments (see Note 12). The cash paid at closing was funded through borrowings under the Partnership's credit facility. The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act) (see Note 12).

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).

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:	
Cash and cash equivalents	\$ 372
Accounts receivable	5,253
Prepaid expenses and other	131
Total current assets	5,756
Property, plant and equipment	208,491
Other assets, net	2,344
Total assets acquired	\$ 216,591
Liabilities:	
Accounts payable	\$ 676
Revenue distribution payable	3,091
Accrued liabilities	1,816
Total current liabilities	5,583
Asset retirement obligation and other	2,418
Total liabilities assumed	8,001
Net assets acquired	\$ 208,590

Carrizo Acquisition

On April 30, 2012, the Partnership completed the acquisition of certain oil and natural gas assets from Carrizo Oil and Gas, Inc. (NASDAQ: CRZO; Carrizo) for approximately \$187.0 million in cash. The purchase price was funded through borrowings under the Partnership's credit facility and \$119.5 million of net proceeds from the sale of 6.0 million of its common units at a negotiated purchase price per unit of \$20.00, of which \$5.0 million was purchased by certain executives of the Partnership. The common units were issued in a private transaction exempt from registration under Section 4(2) of the Securities Act (see Note 12).

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).

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:	
Property, plant and equipment	\$ 190,946
Liabilities:	
Asset retirement obligation	3,903
Net assets acquired	\$ 187,043

Pro Forma Financial Information

The following data presents pro forma revenues, net income (loss) and basic and diluted net income (loss) per unit for the Partnership as if the EP Energy Acquisition, including the related borrowings, net proceeds from the issuance of debt and issuances of preferred units had occurred on January 1, 2012. The Partnership prepared these pro forma unaudited financial results for comparative purposes only; they may not be indicative of the results that would have occurred if the EP Acquisition and related offerings had occurred on January 1, 2012 or the results that will be attained in future periods (in thousands, except per share data; unaudited):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Total revenues and other	\$ 104,010	\$ 107,225	\$ 377,085	\$ 274,010
Net loss	(18,784)	(12,449)	(13,988)	(84,848)
Net loss attributable to common limited partners	(24,249)	(15,271)	(28,990)	(80,320)
Net loss attributable to common limited partners per unit:				
Basic and Diluted	\$ (0.41)	\$ (0.26)	\$ (0.49)	\$ (1.36)

Other Acquisition

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

NOTE 4 PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2013	December 31, 2012	Estimated Useful Lives
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in Years

Natural gas and oil properties:			
Proved properties:			
Leasehold interests	\$ 291,333	\$ 244,476	
Pre-development costs	4,328	1,935	
Wells and related equipment	2,135,844	1,222,475	
Total proved properties	2,431,505	1,468,886	
Unproved properties	266,827	292,053	
Support equipment	17,291	13,110	
Total natural gas and oil properties	2,715,623	1,774,049	
Pipelines, processing and compression facilities	42,612	33,092	2 40
Rights of way	267	784	20 40
Land, buildings and improvements	9,207	8,283	3 40
Other	12,919	9,762	3 10
	2,780,628	1,825,970	
Less accumulated depreciation, depletion and amortization	(604,874)	(523,742)	
	\$ 2,175,754	\$ 1,302,228	

During the three and nine months ended September 30, 2013, the Partnership recognized \$0.7 million and \$2.0 million, respectively, of loss on asset disposal, pertaining to its decision not to drill wells on leasehold property that expired during the three and nine months ended September 30, 2013 in Indiana and Tennessee.

During the nine months ended September 30, 2012, the Partnership recognized a \$7.0 million loss on asset disposal, pertaining to its decision to terminate a farm out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm out agreement contained certain well drilling targets for the Partnership to maintain ownership of the South Knox processing plant, which the Partnership's management decided in 2012 not to achieve due to the then current natural gas price environment. As a result, the Partnership's management forfeited its interest in the processing plant and related properties and recorded a loss related to the net book values of those assets during the year ended December 31, 2012.

During the year ended December 31, 2012, the Partnership recognized \$9.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2012. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

NOTE 5 OTHER ASSETS

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

	September 30, 2013	December 31, 2012
Deferred financing costs, net of accumulated amortization of \$10,996 and \$2,388 at September 30, 2013 and December 31, 2012, respectively	\$ 35,289	\$ 14,467
Notes receivable	4,127	
Other	4,052	1,655
	\$ 43,468	\$ 16,122

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 \$2.8 million and \$0.5 million for the three months ended September 30, 2013 and 2012, respectively, and \$5.4 million and \$1.0 million for the nine months ended September 30, 2013 and 2012, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the three and nine months ended September 30, 2013, the Partnership capitalized \$21.3 million of deferred financing costs related to the amended revolving credit facility and the 9.25% Senior Notes due August 15, 2021 into other assets, net on the Partnership's consolidated balance sheet as a result of the EP Energy Acquisition (see Note 3). During the nine months ended September 30, 2013, the Partnership also recognized \$3.2 million for accelerated amortization of deferred financing costs associated with the retirement of its term loan facility and a portion of the outstanding indebtedness under its revolving credit facility with a portion of the proceeds from its issuance of senior unsecured notes due 2021 (7.75% Senior Notes) (see Note 7). There was no accelerated amortization of deferred financing costs during the three months ended September 30, 2013 and 2012 and during the nine months ended September 30, 2012.

At September 30, 2013, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership's consolidated balance sheet. 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 and nine months ended September 30, 2013, approximately \$25,000 and \$50,000, respectively, of interest income was recognized within other, net on the Partnership's consolidated statements of operations. There was no interest income recognized for the three and nine months ended September 30, 2012. At September 30, 2013, the Partnership recorded no allowance for credit losses within its consolidated balance sheet based upon payment history and ongoing credit evaluations.

NOTE 6 ASSET RETIREMENT OBLIGATIONS

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

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

The Partnership proportionately consolidates its ownership interest of the asset retirement obligations of its Drilling Partnerships. At September 30, 2013, the Drilling Partnerships had \$62.3 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of the Partnership's proportional interest in such liabilities. Under the terms of the respective partnership agreements, the Partnership maintains the right to retain a portion or all of the distributions to the limited partners of its Drilling Partnerships to cover the limited partners' share of the plugging and abandonment costs up to a specified amount per month. During the three and nine months ended September 30, 2013, the Partnership withheld \$0.1 million and \$0.2 million, respectively, of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. No amounts were withheld during the three and nine months ended September 30, 2012. 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		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Asset retirement obligations, beginning of period	\$ 67,732	\$ 51,046	\$ 64,794	\$ 45,779
Liabilities incurred	14,699	2,424	15,943	6,516
Liabilities settled	(158)	(198)	(381)	(448)
Accretion expense	1,294	768	3,211	2,193
Asset retirement obligations, end of period	\$ 83,567	\$ 54,040	\$ 83,567	\$ 54,040

The above accretion expense was included in depreciation, depletion and amortization in the Partnership's consolidated statements of operations and the asset retirement obligation liabilities were included within asset retirement obligations and other in the Partnership's consolidated balance sheets. During the three and nine months ended

September 30, 2013, the Partnership incurred \$14.1 million of future plugging and abandonment costs related to the EP Energy Acquisition it consummated during the period. During the three and nine months ended September 30, 2012, the Partnership incurred \$2.0 million and \$5.9 million, respectively, of future plugging and abandonment costs related to other acquisitions it consummated during those respective periods.

NOTE 7 DEBT

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

	September 30, 2013	December 31, 2012
Revolving credit facility	\$ 425,000	\$ 276,000
Term loan credit facility		75,425
7.75 % Senior Notes due 2021	275,000	
9.25 % Senior Notes due 2021	248,279	
Total debt	948,279	351,425
Less current maturities		
Total long-term debt	\$ 948,279	\$ 351,425

Credit Facility

On July 31, 2013, in connection with the acquisition of assets from EP Energy (see Note 3), the Partnership entered into a second amended and restated credit agreement (Credit Agreement) with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amended and restated the Partnership's existing revolving credit facility. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a current borrowing base of \$835.0 million and a maximum facility amount of \$1.5 billion, which is scheduled to mature in July 2018. At September 30, 2013, \$425.0 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 \$2.1 million was outstanding at September 30, 2013. 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 subsidiaries of the Partnership, other than subsidiary guarantors, are minor. Borrowings under the credit facility bear interest, at the Partnership's election, at either LIBOR plus an applicable margin between 1.75% and 2.75% per annum or the base rate (which is the higher of the bank's prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 0.75% and 1.75% per annum. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.5% per annum if 50% or more of the borrowing base is utilized and 0.375% per annum if less than 50% of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At September 30, 2013, the weighted average interest rate on outstanding borrowings under the credit facility was 2.2%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of September 30, 2013. The Credit Agreement also requires the Partnership to maintain a ratio of Total

Funded Debt (as defined in the Credit Agreement) to four quarters (actual or annualized, as applicable) of EBITDA (as defined in the Credit Agreement) not greater than 4.50 to 1.0 as of the last day of the quarter ended September 30, 2013, 4.25 to 1.0 as of the last day of the quarters ended December 31, 2013 and March 31, 2014 and 4.0 to 1.0 as of the last day of fiscal quarters ending thereafter and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. Based on the definitions contained in the Partnership's Credit Agreement, at September 30, 2013, the Partnership's ratio of current assets to current liabilities was 2.7 to 1.0, and its ratio of Total Funded Debt to EBITDA was 4.2 to 1.0.

Senior Notes

On July 30, 2013, the Partnership issued \$250.0 million of its 9.25% Senior Notes due 2021 (9.25% Senior Notes) in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately \$242.8 million, net of underwriting fees and other offering costs of \$5.5 million. The net proceeds were used to partially fund the EP Energy Acquisition (see Note 3). The 9.25% Senior Notes were presented net of a \$1.7 million unamortized discount as of September 30, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date being February 15, 2014. At any time on or after August 15,

2017, the Partnership may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, the Partnership may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the 9.25% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (the SEC) to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 30, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, the Partnership has agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If the Partnership fails to comply with its obligations to register the 9.25% Senior Notes within the specified time periods, the 9.25% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable.

On January 23, 2013, the Partnership issued \$275.0 million of its 7.75% Senior Notes due 2021 in a private placement transaction at par. The Partnership used the net proceeds of approximately \$267.7 million, net of underwriting fees and other offering costs of \$7.3 million, to repay all of the indebtedness and accrued interest outstanding under its then-existing term loan credit facility and a portion of the amounts outstanding under its revolving credit facility. In connection with the retirement of the Partnership's term loan credit facility and the reduction in its revolving credit facility borrowing base, the Partnership accelerated \$3.2 million of amortization expense related to deferred financing costs during the nine months ended September 30, 2013 (see Note 5). Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019.

In connection with the issuance of the 7.75% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by January 23, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, the Partnership has agreed to file a shelf registration statement with respect to the 7.75% Senior Notes. If the Partnership fails to comply with its obligations to register the 7.75% Senior Notes within the specified time periods, the 7.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable. On July 1, 2013, the Partnership filed a registration statement relating to the exchange offer for the 7.75% Senior Notes.

The 9.25% Senior Notes and 7.75% Senior Notes are guaranteed by certain of the Partnership's material subsidiaries. As of September 30, 2013, the Partnership was a holding company and had no independent assets or operations of its own. The guarantees under the 9.25% Senior Notes and 7.75% Senior Notes are full and unconditional and joint and several, and any subsidiaries of the Partnership, other than the subsidiary guarantors, are minor. There are no restrictions on the Partnership's ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% 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, 2013.

Cash payments for interest by the Partnership were \$15.2 million and \$2.0 million for the nine months ended September 30, 2013 and 2012, 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. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right, but not the obligation, to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

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

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership's consolidated balance sheets as the initial value of the options. The Partnership reflected net derivative assets on its consolidated balance sheets of \$47.7 million and \$20.3 million at September 30, 2013 and December 31, 2012, respectively. Of the \$50.2 million of net gain in accumulated other comprehensive income on the Partnership's consolidated balance sheet at September 30, 2013, if the fair values of the instruments remain at current market values, the Partnership will reclassify \$18.7 million of gains to gas and oil production revenue on its consolidated statement of operations over the next twelve month period as these contracts expire. Aggregate gains of \$31.5 million of gas and oil production revenues will be reclassified to the Partnership's consolidated statements of operations in later periods as the remaining contracts expire. Actual amounts

that will be reclassified will vary as a result of future commodity price changes. Approximately \$1.3 million and \$0.8 million of derivative gains were reclassified from other comprehensive income related to derivative instruments entered into during the three and nine months ended September 30, 2013, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Gain reclassified from accumulated other comprehensive income:				
Gas and oil production revenue	\$ (1,145)	\$ (6,114)	\$ (4,424)	\$ (15,453)
Total	\$ (1,145)	\$ (6,114)	\$ (4,424)	\$ (15,453)

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

			Net Amount
	Gross	Gross	Assets of
	Amounts of	Amounts	Presented in the
	Recognized	Offset in the	Consolidated
	Assets	Consolidated	Balance Sheets
		Balance Sheets	
Offsetting Derivative Assets			
As of September 30, 2013			
Current portion of derivative assets	\$ 23,643	\$ (4,169)	\$ 19,474
Long-term portion of derivative assets	32,060	(3,560)	28,500
Current portion of derivative liabilities	254	(254)	
Total derivative assets	\$ 55,957	\$ (7,983)	\$ 47,974
As of December 31, 2012			
Current portion of derivative assets	\$ 14,248	\$ (1,974)	\$ 12,274
Long-term portion of derivative assets	14,724	(5,826)	8,898
Long-term portion of derivative liabilities	800	(800)	
Total derivative assets	\$ 29,772	\$ (8,600)	\$ 21,172
	Gross	Gross	Net Amount of
	Amounts of	Amounts	Liabilities Presented
	Recognized	Offset in the	in the Consolidated
	Liabilities	Consolidated	Balance Sheets
		Balance Sheets	
Offsetting Derivative Liabilities			
As of September 30, 2013			
Current portion of derivative assets	\$ (4,169)	\$ 4,169	\$
Long-term portion of derivative assets	(3,560)	3,560	
Current portion of derivative liabilities	(572)	254	(318)
Long-term portion of derivative liabilities			
Total derivative liabilities	\$ (8,301)	\$ 7,983	\$ (318)
As of December 31, 2012			
Current portion of derivative assets	\$ (1,974)	\$ 1,974	\$
Long-term portion of derivative assets	(5,826)	5,826	
Long-term portion of derivative liabilities	(1,688)	800	(888)
Total derivative liabilities	\$ (9,488)	\$ 8,600	\$ (888)

The Partnership enters into commodity future option and collar contracts to achieve more predictable cash flows by hedging its exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile Exchange (NYMEX) futures and options contracts and non-regulated over-the-counter futures

contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the physical delivery of the commodity. Crude oil contracts are based on a West Texas Intermediate (WTI) index. NGL fixed price swaps are priced based on a WTI crude oil index. These contracts have qualified and been designated as cash flow hedges and were recorded at their fair values.

In June 2012, the Partnership received approximately \$3.9 million in net proceeds from the early termination of natural gas and oil derivative positions for production periods from 2015 through 2016. In conjunction with the early termination of these derivatives, the Partnership entered into new derivative positions at prevailing prices at the time of the transaction. The net proceeds from the early termination of these derivatives were used to reduce indebtedness under the Partnership's credit facility (see Note 7). The gain recognized upon the early termination of these derivative positions will continue to be reported in accumulated other comprehensive income and will be reclassified into the Partnership's consolidated statements of operations in the same periods in which the hedged production revenues would have been recognized in earnings.

During the nine months ended September 30, 2013, the Partnership entered into contracts which provided the option to enter into swap contracts for future production periods (swaptions) up through September 30, 2013 for production volumes

related to assets acquired from EP Energy (see Note 3). In connection with the swaption contracts, the Partnership paid premiums of \$14.5 million, which represented their fair value on the date the transactions were initiated and was initially recorded as derivative assets on the Partnership's consolidated balance sheet and was fully amortized as of September 30, 2013. Swaption premiums paid are amortized over the period from initiation of the contract through termination date. For the three and nine months ended September 30, 2013, the Partnership recognized \$13.2 million and \$14.5 million, respectively, of amortization expense in other, net on the Partnership's consolidated statement of operations related to the swaption contracts.

During the nine months ended September 30, 2012, the Partnership entered into swaptions contracts up through May 31, 2012 for production volumes related to wells acquired from Carrizo (see Note 3). In connection with the swaption contracts, the Partnership paid premiums of \$4.6 million, which represented their fair value on the date the transactions were initiated and was initially recorded as a derivative asset on the Partnership's consolidated balance sheet and was fully amortized as of September 30, 2012. For the nine months ended September 30, 2012, the Partnership recorded approximately \$4.6 million of amortization expense in other, net on the Partnership's consolidated statements of operations related to the swaption contracts. No amortization expense was recorded on the Partnership's consolidated statement of operations for the three months ended September 30, 2012.

The Partnership recognized gains of \$1.1 million and \$6.1 million for the three months ended September 30, 2013 and 2012, respectively, and \$4.4 million and \$15.5 million for the nine months ended September 30, 2013 and 2012, respectively, on settled contracts covering commodity production. These gains were included within gas and oil production revenue in the Partnership's consolidated statements of operations. As the underlying prices and terms in the Partnership's derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the three and nine months ended September 30, 2013 and 2012 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At September 30, 2013, 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⁾
2013	15,597,400	\$ 3.909	\$ 4,881
2014	60,153,000	\$ 4.152	17,536
2015	50,274,500	\$ 4.240	9,113
2016	43,946,300	\$ 4.318	6,556
2017	24,840,000	\$ 4.532	5,501
2018	3,960,000	\$ 4.716	1,030

\$ 44,617

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu) ⁽¹⁾	Average Floor and Cap (per MMBtu) ⁽¹⁾	Fair Value Asset/(Liability) (in thousands) ⁽²⁾
2013	Puts purchased	1,380,000	\$ 4.395	\$ 1,134
2013	Calls sold	1,380,000	\$ 5.443	(2)
2014	Puts purchased	3,840,000	\$ 4.221	2,257
2014	Calls sold	3,840,000	\$ 5.120	(284)
2015	Puts purchased	3,480,000	\$ 4.234	2,059
2015	Calls sold	3,480,000	\$ 5.129	(655)
				\$ 4,509

Natural Gas Put Options Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu) ⁽¹⁾	Average Fixed Price (per MMBtu) ⁽¹⁾	Fair Value Asset (in thousands) ⁽²⁾
2013	Puts purchased	540,000	\$ 3.450	\$ 25
2014	Puts purchased	1,800,000	\$ 3.800	541
2015	Puts purchased	1,440,000	\$ 4.000	608
2016	Puts purchased	1,440,000	\$ 4.150	762
				\$ 1,936

Natural Gas Liquids Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl) ⁽¹⁾	Average Fixed Price (per Bbl) ⁽¹⁾	Fair Value Asset/(Liability) (in thousands) ⁽³⁾
2013	36,000	\$ 93.656	\$ (327)
2014	105,000	\$ 91.571	(389)
2015	96,000	\$ 88.550	
2016	84,000	\$ 85.651	68
2017	60,000	\$ 83.780	45
			\$ (603)

Natural Gas Liquids Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal) ⁽¹⁾	Average Fixed Price (per Gal) ⁽¹⁾	Fair Value Asset (in thousands) ⁽⁴⁾
2014	2,520,000	\$ 0.303	100
			\$ 100

Natural Gas Liquids Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal) ⁽¹⁾	Average Fixed Price (per Gal) ⁽¹⁾	Fair Value Asset/(Liability) (in thousands) ⁽⁵⁾
2013	3,864,000	1.084	4
2014	11,592,000	\$ 0.996	(11)
			\$ (7)

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl) ⁽¹⁾	Average Fixed Price (per Bbl) ⁽¹⁾	Fair Value Asset/(Liability) (in thousands) ⁽³⁾
2013	170,200	\$ 93.738	\$ (1,530)
2014	552,000	\$ 92.668	(1,515)
2015	567,000	\$ 88.144	(211)
2016	225,000	\$ 85.523	155
2017	132,000	\$ 83.305	39
			\$ (3,062)

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl) ⁽¹⁾	Average Floor and Cap (per Bbl) ⁽¹⁾	Fair Value Asset/(Liability) (in thousands) ⁽³⁾
2013	Puts purchased	20,000	\$ 90.000	\$ 12
2013	Calls sold	20,000	\$ 116.396	(5)
2014	Puts purchased	41,160	\$ 84.169	132
2014	Calls sold	41,160	\$ 113.308	(76)
2015	Puts purchased	29,250	\$ 83.846	181
2015	Calls sold	29,250	\$ 110.654	(78)
				\$ 166
			Total net assets	\$ 47,656

(1) MMBtu represents million British Thermal Units; Bbl represents barrels; Gal represents gallons.

(2) Fair value based on forward NYMEX natural gas prices, as applicable.

(3) Fair value based on forward WTI crude oil prices, as applicable.

(4) Fair value based on forward Mt. Belvieu ethane prices, as applicable.

(5) Fair value based on forward Mt. Belvieu propane prices, as applicable.

At September 30, 2013, the Partnership had net cash proceeds of \$5.9 million related to hedging positions monetized on behalf of the Drilling Partnerships' limited partners, which were included within cash and cash equivalents on the Partnership's consolidated balance sheet. The Partnership will allocate the monetization net proceeds to the Drilling Partnerships' limited partners based on their natural gas and oil production generated over the period of the original derivative contracts. The Partnership reflected the remaining hedge monetization proceeds within current and long-term portion of derivative payable to Drilling Partnerships on its consolidated balance sheets as of September 30, 2013 and December 31, 2012.

In June 2012, the Partnership entered into natural gas put option contracts, which related to future natural gas production of the Drilling Partnerships. Therefore, a portion of any unrealized derivative gain or loss is allocable to the limited partners of the Drilling Partnerships based on their share of estimated gas production related to the derivatives not yet settled. At September 30, 2013, net unrealized derivative assets of \$1.9 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At September 30, 2013, the Partnership had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under its revolving credit facility (see Note 7), the Partnership is required to utilize this secured hedge facility for future commodity risk management activity for its equity production volumes within the participating Drilling Partnerships. Each participating Drilling 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 and by a guarantee of the general partner of the Drilling Partnership. The Partnership, as general partner of the Drilling Partnerships, administers the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

NOTE 9 FAIR VALUE OF FINANCIAL INSTRUMENTS

Management has established a hierarchy to measure the Partnership's financial instruments at fair value, which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 Unobservable inputs that reflect the entity's own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership uses a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 8). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership's commodity derivative contracts are valued based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 assets and liabilities within the same class of nature and risk. These derivative instruments are calculated by utilizing commodity indices' quoted prices for futures and options contracts traded on open markets that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Information for assets and liabilities measured at fair value at September 30, 2013 and December 31, 2012 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
As of September 30, 2013				
Derivative assets, gross				
Commodity swaps	\$	\$ 48,248	\$	\$ 48,248
Commodity puts		1,936		1,936
Commodity options		5,773		5,773
Commodity swaptions				
Total derivative assets, gross		55,957		55,957
Derivative liabilities, gross				
Commodity swaps		(7,202)		(7,202)
Commodity puts				
Commodity options		(1,099)		(1,099)
Total derivative liabilities, gross		(8,301)		(8,301)

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Total derivatives, fair value, net	\$	\$ 47,656	\$	\$ 47,656
		Level 1	Level 2	Level 3
				Total
As of December 31, 2012				
Derivative assets, gross				
Commodity swaps	\$	\$ 15,859	\$	\$ 15,859
Commodity puts		2,991		2,991
Commodity options		10,923		10,923
Total derivative assets, gross		29,773		29,773
Derivative liabilities, gross				
Commodity swaps		(6,813)		(6,813)
Commodity puts				
Commodity options		(2,676)		(2,676)
Total derivative liabilities, gross		(9,489)		(9,489)
Total derivatives, fair value, net	\$	\$ 20,284	\$	\$ 20,284

Other Financial Instruments

The estimated fair value of the Partnership's other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts that the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership's other current assets and liabilities on its consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair value of the Partnership's long-term debt at September 30, 2013, which consists of its Senior Notes and outstanding borrowings under its revolving credit facility (see Note 7), was \$936.2 million compared with the carrying amount of \$948.3 million. At September 30, 2013 and December 31, 2012, the carrying value of outstanding borrowings under the Partnership's revolving credit facility (see Note 7), which bears interest at variable interest rates, approximated its estimated fair value. The estimated fair values of the Partnership's Senior Notes were based upon the market approach and calculated using yields of the Partnership as provided by financial institutions and thus was categorized as a Level 3 value.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Management estimates the fair value of its asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors at the date of establishment of an asset retirement obligation such as: amounts and timing of settlements, the credit-adjusted risk-free rate of the Partnership and estimated inflation rates.

Information for assets and liabilities that were measured at fair value on a nonrecurring basis for the three and nine months ended September 30, 2013 and 2012 were as follows (in thousands):

	Three Months Ended September 30,			
	2013		2012	
	Level 3	Total	Level 3	Total
Asset retirement obligations	\$ 14,699	\$ 14,699	\$ 2,424	\$ 2,424
Total	\$ 14,699	\$ 14,699	\$ 2,424	\$ 2,424

	Nine Months Ended September 30,			
	2013		2012	
	Level 3	Total	Level 3	Total
Asset retirement obligations	\$ 15,943	\$ 15,943	\$ 6,516	\$ 6,516
Total	\$ 15,943	\$ 15,943	\$ 6,516	\$ 6,516

During the three and nine months ended September 2013, the Partnership completed the acquisitions of certain oil and gas assets from EP Energy (see Note 3). During the nine months ended September 30, 2012, the Partnership completed the acquisitions of certain oil and gas assets from Carrizo and certain proved reserves and associated assets from Titan (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were

measured under the Partnership's existing methodology for recognizing an estimated liability for the plugging and abandonment of its gas and oil wells (see Note 6). These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are subject to change. The fair value of the warrants associated with the Class C preferred units (see Note 12) was measured using a Black-Scholes pricing model which is based on Level 3 inputs including conversion price of \$23.10, discount rate of 0.21% and estimated volatility rate of 35%.

NOTE 10 CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with Drilling Partnerships. The Partnership conducts certain activities through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Partnership serves as general partner and operator of the Drilling Partnerships and assumes customary rights and obligations for the Drilling Partnerships. As the general partner, the Partnership is liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the Drilling Partnerships if it breaches its responsibilities with respect to the operations of the Drilling Partnerships. The Partnership is entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership's revenue and costs and expenses according to the respective partnership agreements.

Relationship with Atlas Pipeline Partners, L.P. The Partnership's general partner, ATLS, also maintains a general partner ownership interest in Atlas Pipeline Partners, L.P. (APL), a publicly traded Delaware master limited partnership (NYSE: APL) and midstream energy service provider engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States. In the Chattanooga Shale, a portion of the natural gas produced by the Partnership is gathered and processed by APL. For the three month periods ended September 30, 2013 and 2012, \$0.1 million and \$0.2 million, respectively, of gathering fees were paid by the Partnership to APL. For the nine months ended September 30, 2013 and 2012, \$0.2 million and \$0.4 million, respectively, of gathering fees were paid by the Partnership to APL, respectively.

In addition, in Lycoming County, Pennsylvania, APL has agreed to provide assistance in the design and construction management services for the Partnership with respect to a pipeline. The total estimated price for the project is under \$2.5 million, of which \$1.6 million had been reimbursed to APL as of September 30, 2013.

NOTE 11 COMMITMENTS AND CONTINGENCIES

General Commitments

The Partnership is the managing general partner of the Drilling Partnerships and has agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. Subject to certain conditions, investor partners in certain Drilling Partnerships have the right to present their interests for purchase by the Partnership, as managing general partner. The Partnership is not obligated to purchase more than 5% to 10% of the units in any calendar year. Based on its historical experience, as of September 30, 2013, the management of the Partnership believes that any such liability incurred would not be material. Also, the Partnership has agreed to subordinate a portion of its share of net partnership revenues from the Drilling Partnerships to the benefit of the investor partners until they have received specified returns, typically 10% per year determined on a cumulative basis, over a specific period, typically the first five to seven years, in accordance with the terms of the partnership agreements. For the three months ended September 30, 2013 and 2012, \$2.2 million and \$1.8 million, respectively, and \$6.5 million and \$3.6 million for the nine months ended September 30, 2013 and 2012, respectively, of the Partnership's revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the Drilling Partnerships.

Certain of the Partnership's executives are parties to employment agreements with ATLS that provide compensation and certain other benefits. The agreements also provide for severance payments under certain circumstances.

As of September 30, 2013, the Partnership is committed to expend approximately \$67.7 million, principally on drilling and completion expenditures and throughput commitments.

Legal Proceedings

On August 3, 2011, CNX Gas Company LLC (CNX) filed a lawsuit in the United States District Court for the Eastern District of Tennessee at Knoxville styled CNX Gas Company LLC vs. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC, and Scott Boruff, No. 3:11-cv-00362. On April 16, 2012, Atlas Energy Tennessee, LLC, an indirect wholly-owned subsidiary of the Partnership, was brought into the lawsuit by way of Amended Complaint. On April 23, 2012, the Court dismissed Chevron Appalachia, LLC as a party on the grounds of lack of subject matter jurisdiction over that entity.

The lawsuit alleged that CNX entered into a Letter of Intent with Miller Energy Resources, Inc. (Miller Energy) for the purchase by CNX of certain leasehold interests containing oil and natural gas rights, representing around 30,000 acres in East Tennessee. The lawsuit also alleged that Miller Energy breached the Letter of Intent by refusing to close by the date provided and by allegedly entertaining offers from third parties for the same leasehold interests. Allegations of inducement of breach of contract and related claims were made by CNX against the remaining defendants, on the theory that these parties knew of the terms of the Letter of Intent and induced Miller Energy to breach the Letter of Intent. CNX was seeking \$15.5 million in damages. The Partnership asserted that it acted in good faith and believed that the outcome of the litigation would be resolved in its favor.

In early September 2013, Atlas Energy Tennessee, LLC, was dismissed as a party on jurisdictional grounds.

The Partnership is also a party to various routine legal proceedings arising out of the ordinary course of its business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on the Partnership's financial condition or results of operations.

NOTE 12 ISSUANCES OF UNITS

Equity Offerings

In July 2013, in connection with the closing of the EP Energy Acquisition (see Note 3), the Partnership issued 3,749,986 of its newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of \$23.10, for proceeds of \$86.6 million. The Class C preferred units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act. The Class C preferred units pay cash distributions in an amount equal to the greater of (i) \$0.51 per unit and (ii) the distributions payable on each common unit at each declared quarterly distribution date. The initial Class C preferred distribution was paid for the quarter ending September 30, 2013. The Class C preferred units have no voting rights, except as set forth in the certificate of designation for the Class C preferred units, which provides, among other things, that the affirmative vote of 75% of the Class C Preferred Units is required to repeal such certificate of designation. Holders of the Class C preferred units have the right to convert the Class C preferred units on a one-for-one basis, in whole or in part, into common units at any time before July 31, 2016. Unless previously converted, all Class C preferred units will convert into common units on July 31, 2016. Upon issuance of the Class C preferred units, ATLS, as purchaser of the Class C preferred units, received 562,497 warrants to purchase the Partnership's common units at an exercise price equal to the face value of the Class C preferred units. The warrants were exercisable beginning October 29, 2013 into an equal number of common units of the Partnership at an exercise price of \$23.10 per unit, subject to adjustments provided therein. The warrants will expire on July 31, 2016. ATLS was granted certain registration rights with respect to the common units underlying the Class C preferred units and the common units issuable upon exercise of the warrants.

Upon issuance of the Class C preferred units and warrants on July 31, 2013, the Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and upon exercise of the warrants. The Partnership agreed to use commercially reasonable efforts to file such registration statement within 90 days of the conversion of the Class C preferred units into common units or the exercise of the warrants.

In June 2013, in connection with entering the EP Energy Acquisition, the Partnership sold an aggregate of 14,950,000 of its common limited partner units (including a 1,950,000 over-allotment) in a public offering at a price of \$21.75 per unit, yielding net proceeds of approximately \$313.1 million. The Partnership utilized the net proceeds from the sale to repay the outstanding balance under its revolving credit facility (see Note 7).

In May 2013, the Partnership entered into an equity distribution program with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution program, the Partnership may sell, from time to time through the agents, common units having an aggregate offering price of up to \$25.0 million. Sales of common limited partner units, if any, may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined in Rule 415 of the Securities Act of 1933, as amended, including sales made directly on the New York Stock Exchange, the existing trading market for the common limited partner units, or sales

made to or through a market maker other than on an exchange or through an electronic communications network. The Partnership will pay each of the agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common limited partner units sold through such agent. During the nine months ended September 30, 2013, the Partnership issued 309,174 common limited partner units under the equity distribution program for net proceeds of \$7.0 million, net of \$0.4 million in commissions paid. No common limited partner units were issued under the equity distribution program during the three months ended September 30, 2013. The Partnership utilized the net proceeds from the sale to repay borrowings outstanding under its revolving credit facility.

In November and December 2012, in connection with entering into a purchase agreement to acquire certain producing wells and net acreage from DTE, the Partnership sold an aggregate of 7,898,210 of its common limited partner units in a public offering at a price of \$23.01 per unit, yielding net proceeds of approximately \$174.5 million. The Partnership utilized the net proceeds from the sale to repay a portion of the outstanding balance under its revolving credit facility and \$2.2 million under its term loan credit facility.

In July 2012, the Partnership completed the acquisition of certain proved reserves and associated assets in the Barnett Shale from Titan in exchange for 3.8 million Partnership common units and 3.8 million newly-created convertible Class B preferred units (which have an estimated collective value of \$193.2 million, based upon the closing price of the Partnership's publicly traded common units as of the acquisition closing date), as well as \$15.4 million in cash for closing adjustments (see Note 3). The preferred units are voluntarily convertible to common units on a one-for-one basis within three years of the acquisition closing date at a strike price of \$26.03 plus all unpaid preferred distributions per unit, and will be mandatorily

converted to common units on the third anniversary of the issuance. While outstanding, the preferred units will receive regular quarterly cash distributions equal to the greater of (i) \$0.40 and (ii) the quarterly common unit distribution.

The Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC by January 25, 2013 to register the resale of the common units issued on the acquisition closing date and those issuable upon conversion of the preferred units. The Partnership agreed to use its commercially reasonable efforts to have the registration statement declared effective by March 31, 2013, and to cause the registration statement to be continuously effective until the earlier of (i) the date as of which all such common units registered thereunder are sold by the holders and (ii) one year after the date of effectiveness. On September 19, 2012, the Partnership filed a registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement, and the registration statement was declared effective by the SEC on October 2, 2012.

In April 2012, the Partnership completed the acquisition of certain oil and gas assets from Carrizo (see Note 3). To partially fund the acquisition, the Partnership sold 6.0 million of its common units in a private placement at a negotiated purchase price per unit of \$20.00, for net proceeds of \$119.5 million, of which \$5.0 million was purchased by certain executives of the Partnership. The common units issued by the Partnership are subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that the Partnership would (a) file a registration statement with the SEC by October 30, 2012 and (b) cause the registration statement to be declared effective by the SEC by December 31, 2012. On July 11, 2012, the Partnership filed a registration statement with the SEC for the common units subject to the registration rights agreement in satisfaction of one of the requirements of the registration rights agreement noted previously. On August 28, 2012, the registration statement was declared effective by the SEC.

Common Unit Distribution

In February 2012, the board of directors of ATLS general partner approved the distribution of approximately 5.24 million Partnership common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 Partnership limited partner units for each of ATLS common units owned on the record date of February 28, 2012. The distribution of these limited partner units represented approximately 20.0% of the common limited partner units outstanding (see Note 1).

NOTE 13 CASH DISTRIBUTIONS

The Partnership has a cash distribution policy under which it distributes, within 45 days following the end of each calendar quarter, all of its available cash (as defined in the partnership agreement) for that quarter to its common unitholders and general partner. If the Partnership's common unit distributions in any quarter exceed specified target levels, ATLS will receive between 13% and 48% of such distributions in excess of the specified target levels.

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Distributions declared by the Partnership from its formation through September 30, 2013 were as follows (in thousands, except per unit amounts):

Date Cash Distribution	For Quarter Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners	Total Cash Distribution To Preferred Partners	Total Cash Distribution to the General Partners Class A Units
May 15, 2012	March 31, 2012	\$ 0.12 ⁽¹⁾	\$ 3,144	\$	\$ 64
August 14, 2012	June 30, 2012	\$ 0.40	\$ 12,891	\$	\$ 263
November 14, 2012	September 30, 2012	\$ 0.43	\$ 15,510	\$ 1,652	\$ 350
February 14, 2013	December 31, 2012	\$ 0.48	\$ 21,107	\$ 1,841	\$ 618
May 15, 2013	March 31, 2013	\$ 0.51	\$ 22,428	\$ 1,957	\$ 946
August 14, 2013	June 30, 2013	\$ 0.54	\$ 32,097	\$ 2,072	\$ 1,884

(1) Represents a pro-rated cash distribution of \$0.40 per common limited partner unit for the period from March 5, 2012, the date ATLS exploration and production assets were transferred to the Partnership, to March 31, 2012.

On October 24, 2013, the Partnership declared a cash distribution of \$0.56 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2013. The \$40.0 million distribution,

including \$2.4 million and \$4.2 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2013 to unitholders of record at the close of business on November 6, 2013.

NOTE 14 BENEFIT PLAN

2012 Long-Term Incentive Plan

The Partnership's 2012 Long-Term Incentive Plan (2012 LTIP), effective March 2012, provides incentive awards to officers, employees and directors and employees of the general partner and its affiliates, consultants and joint venture partners (collectively, the Participants), who perform services for the Partnership. The 2012 LTIP is administered by the board of the general partner, a committee of the board or the board (or committee of the board) of an affiliate (the LTIP Committee). Under the 2012 LTIP, the LTIP Committee may grant awards of phantom units, restricted units or unit options for an aggregate of 2,900,000 common limited partner units. At September 30, 2013, the Partnership had 2,338,500 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 350,668 phantom units, restricted units and unit options available for grant.

Upon a change in control, as defined in the 2012 LTIP, all unvested awards held by directors will immediately vest in full. In the case of awards held by eligible employees, following a change in control, upon the eligible employee's termination of employment without cause, as defined in the 2012 LTIP, or upon any other type of termination specified in the eligible employee's applicable award agreement(s), any unvested award will immediately vest in full and, in the case of options, become exercisable for the one-year period following the date of termination of employment, but in any case not later than the end of the original term of the option.

In connection with a change in control, the LTIP Committee, in its sole and absolute discretion and without obtaining the approval or consent of the unitholders or any Participant, but subject to the terms of any award agreements and employment agreements to which the general partner (or any affiliate) and any Participant are party, may take one or more of the following actions (with discretion to differentiate between individual Participants and awards for any reason):

- cause awards to be assumed or substituted by the surviving entity (or affiliate of such surviving entity);
- accelerate the vesting of awards as of immediately prior to the consummation of the transaction that constitutes the change in control so that awards will vest (and, with respect to options, become exercisable) as to the common units that otherwise would have been unvested so that participants (as holders of awards granted under the new equity plan) may participate in the transaction;

provide for the payment of cash or other consideration to participants in exchange for the cancellation of outstanding awards (in an amount equal to the fair market value of such cancelled awards);

- terminate all or some awards upon the consummation of the change-in-control transaction, but only if the LTIP Committee provides for full vesting of awards immediately prior to the consummation of such transaction; and
- make such other modifications, adjustments or amendments to outstanding awards or the new equity plan as the LTIP Committee deems necessary or appropriate.

Phantom Units

Phantom units represent rights to receive a common unit, an amount of cash or other securities or property based on the value of a common unit, or a combination of common units and cash or other securities or property. Phantom units are subject to terms and conditions determined by the LTIP Committee, which may include vesting restrictions. In tandem with phantom unit grants, the LTIP Committee may grant distribution equivalent rights (DERs), which are the right to receive an amount in cash, securities, or other property equal to, and at the same time as, the cash distributions or other distributions of securities or other property made by the Partnership with respect to a common unit during the period that the underlying phantom unit is outstanding. Phantom units granted under the 2012 LTIP generally will vest 25% of the original granted amount on each of the next four anniversaries of the date of grant. Of the phantom units outstanding under the 2012 LTIP at September 30, 2013, 279,387 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at September 30, 2013 include DERs. During the three and nine months ended September 30, 2013, the

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Partnership paid \$0.5 million and \$1.5 million, respectively, with respect to the 2012 LTIP's DERs. During the three and nine months ended September 30, 2012, respectively, the Partnership paid \$0.3 million with respect to DERs. These amounts were recorded as reductions of partners' capital on the Partnership's consolidated balance sheet.

The following table sets forth the 2012 LTIP phantom unit activity for the periods indicated:

	Three Months Ended September 30,			
	2013	Weighted Average Grant Date Fair Value	2012	Weighted Average Grant Date Fair Value
	Number of Units		Number of Units	
Outstanding, beginning of period	845,932	\$ 24.51	810,476	\$ 24.69
Granted	37,191	21.86	129,500	25.23
Vested and issued ⁽¹⁾	(33,123)	24.72		
Forfeited			(1,000)	24.67
Outstanding, end of period ⁽²⁾⁽³⁾	850,000	\$ 24.38	938,976	\$ 24.76
Vested and not yet issued ⁽⁴⁾	7,749	\$ 25.51		\$
Non-cash compensation expense recognized (in thousands)		\$ 2,045		\$ 2,915

	Nine Months Ended September 30,			
	2013	Weighted Average Grant Date Fair Value	2012	Weighted Average Grant Date Fair Value
	Number of Units		Number of Units	
Outstanding, beginning of year	948,476	\$ 24.76		\$
Granted	128,981	22.07	939,976	24.76
Vested and issued ⁽¹⁾	(204,582)	24.70		
Forfeited	(22,875)	24.23	(1,000)	24.67
Outstanding, end of period ⁽²⁾⁽³⁾	850,000	\$ 24.38	938,976	\$ 24.76
Vested and not yet issued ⁽⁴⁾	7,749	\$ 25.51		\$
Non-cash compensation expense recognized (in thousands)		\$ 7,329		\$ 4,655

- (1) The intrinsic value of phantom unit awards vested and issued during the three and nine months ended September 30, 2013 was \$4.9 million and \$4.2 million, respectively. No phantom unit awards vested and were issued during the three and nine months ended September 30, 2012.
- (2) The aggregate intrinsic value for phantom unit awards outstanding at September 30, 2013 was \$17.8 million.
- (3) There was approximately \$40,000 and \$31,000 recognized as liabilities on the Partnership's consolidated balance sheet at September 30, 2013 and December 31, 2012, respectively, representing 7,939 and 3,476 units, respectively, due to the option of the participants to settle in cash instead of units. The respective weighted average grant date fair value for these units was \$25.19 and \$28.75 at September 30, 2013 and December 31, 2012, respectively.
- (4) The intrinsic value of phantom unit awards vested, but not yet issued at September 30, 2013 was \$0.2 million. No phantom unit awards had vested, but had not yet been issued at September 30, 2012.

At September 30, 2013, the Partnership had approximately \$10.8 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards.

Unit Options

A unit option is the right to purchase a Partnership common unit in the future at a predetermined price (the exercise price). The exercise price of each option is determined by the LTIP Committee and may be equal to or greater than the fair market value of a common unit on the date the option is granted. The LTIP Committee will determine the vesting and exercise restrictions applicable to an award of options, if any, and the method by which the exercise price may be paid by the Participant. Unit option awards expire 10 years from the date of grant. Unit options granted under the 2012 LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. There were 372,000 unit options outstanding under the 2012 LTIP at September 30, 2013 that will vest within the following twelve months. No cash was received from the exercise of options for the three and nine months ended September 30, 2013 and 2012.

The following table sets forth the 2012 LTIP unit option activity for the periods indicated:

	Three Months Ended September 30,		Three Months Ended September 30,	
	2013	2012	2013	2012
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	1,494,750	\$ 24.67	1,499,500	\$ 24.67
Granted			18,000	25.18
Exercised ⁽¹⁾				
Forfeited	(6,250)	24.67	(2,000)	24.67
Outstanding, end of period ⁽²⁾⁽³⁾	1,488,500	\$ 24.67	1,515,500	\$ 24.68
Options exercisable, end of period ⁽⁴⁾	371,375	\$ 24.67		\$
Non-cash compensation expense recognized (in thousands)		\$ 915		\$ 1,927
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of year	1,515,500	\$ 24.68		\$
Granted	2,500	22.88	1,517,500	24.68
Exercised ⁽¹⁾				
Forfeited	(29,500)	24.74	(2,000)	24.67
Outstanding, end of period ⁽²⁾⁽³⁾	1,488,500	\$ 24.67	1,515,500	\$ 24.68
Options exercisable, end of period ⁽⁴⁾	371,375	\$ 24.67		\$
Non-cash compensation expense recognized (in thousands)		\$ 2,880		\$ 3,201

- (1) No options were exercised during three and nine months ended September 30, 2013 and 2012.
- (2) The weighted average remaining contractual life for outstanding options at September 30, 2013 was 8.6 years.
- (3) There was no aggregate intrinsic value of options outstanding at September 30, 2013.
- (4) The weighted average remaining contractual life for exercisable options at September 30, 2013 was 8.6 years.
There were no aggregate intrinsic values of options exercisable at September 30, 2013 and 2012. No options were exercisable at September 30, 2012.

At September 30, 2013, the Partnership had approximately \$3.5 million in unrecognized compensation expense related to unvested unit options outstanding under the 2012 LTIP based upon the fair value of the awards. The Partnership used the Black-Scholes option pricing model, which is based on Level 3 inputs, to estimate the weighted average fair value of options granted.

The following weighted average assumptions were used for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Expected dividend yield		2.5%	6.7%	1.5%
Expected unit price volatility		46.0%	35.8%	47.0%
Risk-free interest rate		0.8%	1.1%	1.0%
Expected term (in years)		6.25	6.35	6.25
Fair value of unit options granted \$		\$ 8.72	\$ 3.63	\$ 9.78

Restricted Units

Restricted units are actual common units issued to a participant that are subject to vesting restrictions and evidenced in such manner as the LTIP Committee may deem appropriate, including book-entry registration or issuance of one or more unit certificates. Prior to or upon the grant of an award of restricted units, the LTIP Committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both. A holder of restricted units will have certain rights of holders of common units in general, including the right to vote the restricted units. However, during the period in which the restricted units are subject to vesting restrictions, the holder will not be permitted to sell, assign, transfer, pledge or otherwise encumber the restricted units.

NOTE 15 OPERATING SEGMENT INFORMATION

The Partnership's operations include three reportable operating segments. These operating segments reflect the way the Partnership manages its operations and makes business decisions. Operating segment data for the periods indicated were as follows (in thousands):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Gas and oil production:				
Revenues	\$ 80,332	\$ 24,699	\$ 173,490	\$ 61,323
Operating costs and expenses	(29,419)	(7,295)	(63,670)	(16,247)
Depreciation, depletion and amortization expense	(39,900)	(12,576)	(80,176)	(29,663)
Segment income	\$ 11,013	\$ 4,828	\$ 29,644	\$ 15,413
Well construction and completion:				
Revenues	\$ 10,964	\$ 36,317	\$ 92,293	\$ 92,277
Operating costs and expenses	(9,534)	(31,581)	(80,255)	(79,882)
Segment income	\$ 1,430	\$ 4,736	\$ 12,038	\$ 12,395
Other partnership management: ⁽¹⁾				
Revenues	\$ (211)	\$ 13,727	\$ 20,676	\$ 29,289
Operating costs and expenses	(6,781)	(6,790)	(20,776)	(20,261)
Depreciation, depletion and amortization expense	(1,756)	(1,342)	(4,885)	(4,185)
Segment income (loss)	\$ (8,748)	\$ 5,595	\$ (4,985)	\$ 4,843
Reconciliation of segment income (loss) to net loss:				
Segment income (loss):				
Gas and oil production	\$ 11,013	\$ 4,828	\$ 29,644	\$ 15,413
Well construction and completion	1,430	4,736	12,038	12,395
Other partnership management	(8,748)	5,595	(4,985)	4,843
Total segment income	3,695	15,159	36,697	32,651
General and administrative expenses ⁽²⁾	(31,983)	(16,147)	(63,767)	(48,427)
Chevron transaction expense ⁽²⁾		(7,670)		(7,670)
Interest expense ⁽²⁾	(10,748)	(1,423)	(22,145)	(2,529)
Gain (loss) on asset sales and disposal ⁽²⁾	(661)	2	(2,035)	(7,019)
Net loss	\$ (39,697)	\$ (10,079)	\$ (51,250)	\$ (32,994)
Capital expenditures:				
Gas and oil production	\$ 60,483	\$ 26,321	\$ 176,582	\$ 67,582
Other partnership management	6,370	242	9,780	1,260
Corporate and other	7,091	1,164	17,634	4,537
Total capital expenditures	\$ 73,944	\$ 27,727	\$ 203,996	\$ 73,379

	September 30, 2013	December 31, 2012
Balance sheet		
Goodwill:		
Gas and oil production	\$ 18,145	\$ 18,145
Well construction and completion	6,389	6,389
Other partnership management	7,250	7,250
	\$ 31,784	\$ 31,784
Total assets:		
Gas and oil production	\$ 2,254,509	\$ 1,342,403
Well construction and completion	21,066	62,472
Other partnership management	56,058	47,097
Corporate and other	55,219	46,980
	\$ 2,386,852	\$ 1,498,952

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

(2) The Partnership notes that gain (loss) on asset sales and disposal, general and administrative expenses, Chevron transaction expense and

interest
expense have
not been
allocated to its
reportable
segments as it
would be
impracticable
to reasonably
do so for the
periods
presented.

NOTE 16 SUBSEQUENT EVENTS

Cash Distribution. On October 24, 2013, the Partnership declared a cash distribution of \$0.56 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2013. The \$40.0 million distribution, including \$2.4 million and \$4.2 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2013 to unitholders of record at the close of business on November 6, 2013.

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

Forward-Looking Statements

When used in this Form 10-Q, the words *believes*, *anticipates*, *expects* and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in *Item 1A. Risk Factors* in our annual report on Form 10-K for the year ended December 31, 2012. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements, which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

BUSINESS OVERVIEW

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

At September 30, 2013, Atlas Energy, L.P. (ATLS), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 36.9% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

We were formed in October 2011 to own and operate substantially all of ATLS' exploration and production assets, which were transferred to us on March 5, 2012. In February 2012, the board of directors of ATLS' general partner approved the distribution of approximately 5.24 million of our common units which were distributed on March 13, 2012 to ATLS' unitholders using a ratio of 0.1021 of our limited partner units for each of ATLS' common units owned on the record date of February 28, 2012.

FINANCIAL PRESENTATION

Our consolidated balance sheets at September 30, 2013 and December 31, 2012, the consolidated statements of operations for the three months ended September 30, 2013 and 2012, the consolidated statements of operations for the nine months ended September 30, 2013, and the portion of the consolidated statement of operations for the nine months ended September 30, 2012 subsequent to the transfer of assets on March 5, 2012 include our accounts and our wholly-owned subsidiaries. The portion of the consolidated statement of operations for the nine months ended September 30, 2012 prior to the transfer of assets on March 5, 2012 was derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if we had been operated as an unaffiliated entity. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management's best estimates, in order to derive our financial statements for the periods presented prior to the transfer of assets. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the combination of the financial statements.

SUBSEQUENT EVENTS

Cash Distribution. On October 24, 2013, we declared a cash distribution of \$0.56 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2013. The \$40.0 million distribution, including \$2.4 million and \$4.2 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2013 to unitholders of record at the close of business on November 6, 2013.

RECENT DEVELOPMENTS

EP Energy Acquisition. On July 31, 2013, we completed the acquisition of assets from EP Energy E&P Company, L.P. (EP Energy), a wholly-owned subsidiary of EP Energy, LLC, and EPE Nominee Corp. Pursuant to the purchase and sale

agreement, we acquired certain assets from EP Energy for approximately \$705.9 million in cash, net of purchase price adjustments (the EP Energy Acquisition). The purchase price was funded through borrowings under our revolving credit facility, the issuance of our 9.25% Senior Notes due August 15, 2021, the issuance of 14,950,000 common limited partner units, and the issuance of our newly created Class C convertible preferred units. The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013.

Issuance of Preferred Units. In connection with the closing of the EP Energy Acquisition on July 31, 2013, we issued \$86.6 million of our newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of \$23.10, which was the face value of the units. The Class C preferred units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act. The Class C preferred units pay cash distributions in an amount equal to the greater of (i) \$0.51 per unit and (ii) the distributions payable on each common unit at each declared quarterly distribution date. The initial Class C preferred distribution will be paid for the quarter ending September 30, 2013. The Class C preferred units have no voting rights, except as set forth in the certificate of designation for the Class C preferred units, which provides, among other things, that the affirmative vote of 75% of the Class C Preferred Units is required to repeal such certificate of designation. Holders of the Class C preferred units have the right to convert the Class C preferred units on a one-for-one basis, in whole or in part, into common units at any time before July 31, 2016. Unless previously converted, all Class C preferred units will convert into common units on July 31, 2016. Upon issuance of the Class C preferred units, ATLS, as purchaser of the Class C preferred units, also received 562,497 warrants to purchase our common units at an exercise price equal to the face value of the Class C preferred units. The warrants are exercisable beginning October 29, 2013 into an equal number of our common units at an exercise price of \$23.10 per unit subject to adjustments as provided therein. The warrants will expire on July 31, 2016.

Upon issuance of the Class C preferred units and warrants on July 31, 2013, we entered into a registration rights agreement pursuant to which we agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and upon exercise of the warrants. We agreed to use commercially reasonable efforts to file such registration statement within 90 days of the conversion of the Class C preferred units into common units or the exercise of the warrants.

Credit Facility Amendment. On July 31, 2013, in connection with the acquisition of assets from EP Energy, we entered into a second amended and restated credit agreement (see Credit Facility).

Senior Notes. On July 30, 2013, we issued \$250.0 million of 9.25% Senior Notes due 2021 (9.25% Senior Notes) in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately \$242.8 million, net of underwriting fees and other offering costs of \$5.5 million. The net proceeds were used to partially fund the EP Acquisition (see Recent Developments). The 9.25% Senior Notes were presented combined with a net \$1.7 million unamortized discount as of September 30, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date being February 15, 2014. At any time prior to August 15, 2017, we may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, we may redeem some or all of the 9.25% Senior Notes at the redemption prices of 102.313% and on or after August 15, 2019, We may redeem some or all of the 9.25% Senior

Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, we may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at 109.250%. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, we must offer to repurchase the 9.25% Senior Notes (see Senior Notes).

In connection with the issuance of the 9.25% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (the SEC) to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated not later than 365 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If we fail to comply with our obligations to register the 9.25% Senior Notes within the specified time periods, the 9.25% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable.

Common Unit Offering. In June 2013, in connection with the EP Energy acquisition, we sold an aggregate of 14,950,000 of our common limited partner units (including a 1,950,000 over-allotment) in a public offering at a price of \$21.75 per unit, yielding net proceeds of approximately \$313.1 million (see Issuance of Units). We utilized the net proceeds from the sale to repay the outstanding balance under our revolving credit facility (see Credit Facility).

Equity Distribution Program. In May 2013, we entered into an equity distribution program with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution program, we may sell, from time to time through the agents, common units having an aggregate offering price of up to \$25.0 million. Sales of common limited partner units, if any, may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined in Rule 415 of the Securities Act of 1933, as amended, including sales made directly on the New York Stock Exchange, the existing trading market for the common limited partner units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common limited partner units sold through such agent. During the nine months ended September 30, 2013, we issued 309,174 common limited partner units under the equity distribution program for net proceeds of \$7.0 million, net of \$0.4 million in commissions paid. We utilized the net proceeds from the sale to repay borrowings outstanding under our revolving credit facility (see Issuance of Units).

Senior Notes. On January 23, 2013, we issued \$275.0 million of 7.75% senior unsecured notes due January 15, 2021 (7.75% Senior Notes) in a private placement transaction at par. During the nine months ended September 30, 2013, we used the net proceeds of approximately \$267.7 million, net of underwriting fees and other offering costs of \$7.3 million, to repay all of the indebtedness and accrued interest outstanding under our term loan credit facility and a portion of the amounts outstanding under our revolving credit facility (see Credit Facility). In connection with the retirement of our term loan credit facility and the reduction in our revolving credit facility borrowing base, we accelerated \$3.2 million of amortization expense related to deferred financing costs during the nine months ended September 30, 2013. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. The indenture governing the 7.75% Senior Notes contains covenants, including limitations of our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets.

In connection with the issuance of the 7.75% Senior Notes, we entered into registration rights agreements, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by January 23, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 7.75% Senior Notes. If we fail to comply with our obligations to register the 7.75% Senior Notes within the specified time periods, the 7.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable. On July 1, 2013, we filed a registration statement relating to the exchange offer for the 7.75% Senior Notes.

CONTRACTUAL REVENUE ARRANGEMENTS

Natural Gas. We market the majority of our natural gas production to gas utility companies, gas marketers, local distribution companies and industrial or other end-users. The sales price of natural gas produced is a function of the market in the area and typically tied to a regional index. The production area and pricing indexes are as follows: Appalachian Basin Dominion South Point, Tennessee Gas Pipeline, Transco Leidy Line; Mississippi Lime Southern Star; Barnett Shale and Marble Falls- primarily Waha but with smaller amounts sold into a variety of north Texas outlets; Raton ANR, Panhandle, and NGPL; Black Warrior Basin Southern Natural; New Albany Shale and Antrim Shale- primarily the Texas Gas Zone SL and Chicago Hub spot markets; and Niobrara formation primarily the Cheyenne Hub spot market. We attempt to sell the majority of our natural gas produced at monthly, fixed index prices and a smaller portion at index daily prices.

We do not hold firm transportation obligations on any pipeline that requires payment of transportation fees regardless of natural gas production volumes. As is customary in certain of our other operating areas, we occasionally commit a predictable portion of monthly production to the purchaser in order to maintain a gathering agreement.

Crude Oil. Crude oil produced from our wells flows directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. The crude oil is typically sold at the prevailing spot market price for each region, less appropriate trucking charges. We do not have delivery commitments for fixed and determinable quantities of crude oil in any future periods under existing contracts or agreements.

Natural Gas Liquids. NGLs are extracted from the natural gas stream by processing and fractionation plants enabling the remaining dry gas (low Btu content) to meet pipeline specifications for transport to end users or marketers operating on the receiving pipeline. The resulting dry natural gas is sold as mentioned above and our NGLs are generally priced using the Mont Belvieu (TX) regional processing hub. The cost to process and fractionate the NGLs from the gas stream is typically either a volumetric fee for the gas and liquids processed or a volumetric retention by the processing and fractionation facility. We do not have delivery commitments for fixed and determinable quantities of NGLs in any future periods under existing contracts or agreements.

Investment Partnerships. We generally fund a portion of our drilling activities through sponsorship of tax-advantaged investment drilling partnerships (Drilling Partnerships). In addition to providing capital for our drilling activities, our Drilling Partnerships are a source of fee-based revenues, which are not directly dependent on commodity prices. As managing general partner of the Drilling Partnerships, we receive the following fees:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, we receive a 15% to 18% mark-up on those costs incurred to drill and complete the well;
- Administration and oversight. For each well drilled by a Drilling Partnership, we receive a fixed fee between \$15,000 and \$400,000, depending on the type of well drilled. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of \$75 for the life of the well. Because we coinvest in the Drilling Partnerships, the net fee that we receive is reduced by our proportionate interest in the well;
- Well services. Each Drilling Partnership pays us a monthly per well operating fee, currently \$100 to \$2,000, for the life of the well. Because we coinvest in the Drilling Partnerships, the net fee that we receive is reduced by our proportionate interest in the wells; and
- Gathering. Each royalty owner, Drilling Partnership and certain other working interest owners pay us a gathering fee, which in general is equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from Drilling Partnerships by approximately 3%.

GENERAL TRENDS AND OUTLOOK

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

The areas in which we operate are experiencing a significant increase in natural gas, oil and NGL production related to new and increased drilling for deeper natural gas formations and the implementation of new exploration and production techniques, including horizontal and multiple fracturing techniques. The increase in the supply of natural gas has put a downward pressure on domestic natural gas prices. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, our ability to make payments on our debt and our ability to make distributions to our unitholders, including ATLS, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas production from particular wells decreases. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce.

RESULTS OF OPERATIONS

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various shale plays throughout the United States. We have certain agreements which restrict our ability to drill additional wells in certain areas of Pennsylvania, New York and West Virginia, including portions of the Marcellus Shale, which will expire on February 17, 2014. Through September 30, 2013, we have established production positions in the following operating areas:

- the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas, a hydro-carbon producing shale in which we established a position following our acquisitions of assets from Carrizo Oil & Gas, Inc. (Carrizo), Titan Operating, LLC (Titan) and DTE Energy Company (DTE) during 2012;
- coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming, where we established a position following our acquisition of certain assets from EP Energy during the three months ended September 30, 2013 (see Recent Developments);
- the Appalachia basin, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region;
- the Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area; and
- other operating areas, including the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; the Antrim Shale in Michigan, where we produce out of the biogenic region of the shale similar to the New Albany Shale; and the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled, both gross and for our interest, and the number of gross wells we turned in line during the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
Gross wells drilled:				
Appalachia	3	8	3	22
Barnett/Marble Falls	22	9	53	9
Mississippi Lime/Hunton	6	2	19	4
Niobrara				51
Total	31	19	75	86
Our share of gross wells drilled ⁽¹⁾ :				
Appalachia	1	2	1	6
Barnett/Marble Falls	14	8	40	8
Mississippi Lime/Hunton	2		8	1
Niobrara				15
Total	17	10	49	30
Gross wells turned in line:				
Appalachia	13	13	14	41
Barnett/Marble Falls	17	3	54	3
Mississippi Lime/Hunton	5	2	15	2
Chattanooga				5
Niobrara		26		98
Total	35	44		