Atlas Resource Partners, L.P.
Form 10-Q
August 08, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from to

Commission file number: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

The number of outstanding common limited partner units of the registrant on August 4, 2014 was 81,529,726.

ATLAS RESOURCE PARTNERS, L.P.

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ON FORM 10-Q

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ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$3,993	$ 1,828
Accounts receivable	85,419	58,822
Current portion of derivative asset	255	1,891
Subscriptions receivable	16,336	47,692
Prepaid expenses and other	21,023	10,097
Total current assets	127,026	120,330
Property, plant and equipment, net	2,666,718	2,120,818
Goodwill and intangible assets, net	32,611	32,747
Long-term derivative asset	3,415	27,084
Other assets, net	51,516	42,821
	$2,881,286	$ 2,343,800
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities:		
Accounts payable	$96,778	$ 69,346
Advances from affiliates	27,838	26,742
Liabilities associated with drilling contracts	—	49,377
Current portion of derivative liability	19,983	6,353
Accrued well drilling and completion costs	70,319	40,481
Accrued interest	22,194	20,622
Distribution payable	18,497	—
Accrued liabilities	18,622	30,794
Total current liabilities	274,231	243,715
Long-term debt	1,203,973	942,334
Asset retirement obligations	100,002	89,776
Other long-term liabilities	2,604	684
Commitments and contingencies		
Partners’ Capital:		
General partner’s interest	249	4,482
Preferred limited partners’ interests	180,566	183,477

Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	1,132,694	852,457
Accumulated other comprehensive income (loss)	(14,209)	25,699
Total partners' capital	1,300,476	1,067,291
	$2,881,286	$ 2,343,800

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues:				
Gas and oil production	$104,057	$47,094	$200,302	$93,158
Well construction and completion	16,336	24,851	65,713	81,329
Gathering and processing	3,758	4,463	8,226	8,048
Administration and oversight	4,166	3,391	5,895	4,476
Well services	6,365	4,864	11,844	9,680
Other, net	35	(1,337)	82	(1,317)
Total revenues	134,717	83,326	292,062	195,374
Costs and expenses:				
Gas and oil production	41,763	19,035	78,555	34,251
Well construction and completion	14,206	21,609	57,142	70,721
Gathering and processing	4,273	4,959	8,686	9,372
Well services	2,426	2,305	4,908	4,623
General and administrative	21,315	14,217	37,770	31,784
Depreciation, depletion and amortization	58,001	22,197	108,238	43,405
Total costs and expenses	141,984	84,322	295,299	194,156
Operating income (loss)	(7,267)	(996)	(3,237)	1,218
Interest expense	(13,263)	(4,508)	(26,451)	(11,397)
Gain (loss) on asset sales and disposal	9	(672)	(1,594)	(1,374)
Net loss	(20,521)	(6,176)	(31,282)	(11,553)
Preferred limited partner dividends	(4,424)	(2,071)	(8,823)	(4,028)
Net loss attributable to common limited partners and the general partner	$(24,945)	$(8,247)	$(40,105)	$(15,581)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	$(27,322)	$(9,269)	$(44,486)	$(16,904)
General partner's interest	2,377	1,022	4,381	1,323
Net loss attributable to common limited partners and the general partner	$(24,945)	$(8,247)	$(40,105)	$(15,581)
Net loss attributable to common limited partners per unit:				
Basic and Diluted	$(0.37)	$(0.20)	$(0.66)	$(0.37)
Weighted average common limited partner units outstanding:				
Basic and Diluted	73,900	47,007	67,595	45,499

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss	$(20,521)	$(6,176)	$(31,282)	$(11,553)
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	(28,293)	42,972	(63,136)	18,028
Less: reclassification adjustment for realized (gains) losses of cash flow hedges in net loss	9,185	(2,286)	23,228	(3,279)
Total other comprehensive income (loss)	(19,108)	40,686	(39,908)	14,749
Comprehensive income (loss) attributable to common and preferred limited partners and the general partner	$(39,629)	$34,510	$(71,190)	$3,196

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

(in thousands, except unit data)

(Unaudited)

	General Partner's Interest		Preferred Limited Partners' Interest				Common Limited Partners' Interests		Class C Common Limited Partner Warrants		Accumulated Other Comprehensi	T
	Class A Units	Amount	Class B Units	Amount	Class C Units	Amount	Units	Amount	Warrants	Amount	Income (Loss)	Pa C
2014	1,368,058	$4,482	3,836,554	$96,539	3,749,986	$86,938	59,448,308	$852,457	562,497	$1,176	$25,699	$
f	449,811	—	—	—	—	—	21,850,000	426,393	—	—	—	4
and nits ntive	—	—	—	—	—	—	190,746	3,677	—	—	—	3
ns	—	(1,279)	—	(742)	—	(725)	—	(15,751)	—	—	—	(
ns nd tners neral n	—	(7,335)	—	(5,192)	—	(5,075)	—	(88,368)	—	—	—	(
on nits ntive	—	—	—	—	—	—	—	(1,228)	—	—	—	(
e	—	4,381	—	4,461	—	4,362	—	(44,486)	—	—	—	(
sive	—	—	—	—	—	—	—	—	—	—	(39,908)	(
014	1,817,869	$249	3,836,554	$95,066	3,749,986	$85,500	81,489,054	$1,132,694	562,497	$1,176	$(14,209)	$

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(31,282)	$(11,553)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	108,238	43,405
Loss on asset sales and disposal	1,594	1,374
Non-cash compensation expense	4,353	7,249
Amortization of deferred financing costs	3,711	5,797
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	(3,410)	11,880
Accounts payable and accrued liabilities	(38,163)	(90,097)
Net cash provided by (used in) operating activities	45,041	(31,945)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(94,555)	(130,052)
Net cash paid for acquisitions	(517,453)	—
Other	(148)	(4,056)
Net cash used in investing activities	(612,156)	(134,108)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	838,000	249,000
Repayments under credit facilities	(676,000)	(600,425)
Net proceeds from issuance of long-term debt	97,500	267,811
Distributions paid to unitholders	(105,970)	(48,897)
Net proceeds from issuance of common limited partner units	426,393	320,221
Deferred financing costs, distribution equivalent rights and other	(10,643)	(1,892)
Net cash provided by financing activities	569,280	185,818
Net change in cash and cash equivalents	2,165	19,765
Cash and cash equivalents, beginning of year	1,828	23,188
Cash and cash equivalents, end of period	$3,993	$42,953

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2014

(Unaudited)

NOTE 1 – BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the "Partnership") is a publicly traded Delaware master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas, crude oil and natural gas liquids ("NGL") with operations in basins across the United States. The Partnership sponsors and manages tax-advantaged investment partnerships (the "Drilling Partnerships"), in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities. At June 30, 2014, Atlas Energy, L.P. ("ATLS"), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of the general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 27.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

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

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2013 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States ("U.S. GAAP") for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management's opinion, all adjustments necessary for a fair presentation of the Partnership's financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2013. Certain amounts in the prior year's financial statements have been reclassified to conform to the current year presentation. The results of operations for the three and six months ended June 30, 2014 may not necessarily be indicative of the results of operations for the full year ending December 31, 2014.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership's consolidated balance sheets at June 30, 2014 and December 31, 2013 and the consolidated statements of operations for the three and six months ended June 30, 2014 and 2013 include the accounts of the Partnership and its wholly-owned subsidiaries. Transactions between the Partnership and other ATLS operations have been identified in the consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

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

Use of Estimates

The preparation of the Partnership's consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership's consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired and liabilities assumed. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Differences between estimated and actual amounts are recorded in the following month's financial results. Management believes that the operating results presented for the three and six months ended June 30, 2014 and 2013 represent actual results in all material respects (see "Revenue Recognition").

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. In evaluating the realizability of its accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by management's review of the Partnership's customers' credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At June 30, 2014 and December 31, 2013, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $9.2 million and $4.6 million of inventory at June 30, 2014 and December 31, 2013, respectively, which was included within prepaid expenses and other current assets on the Partnership's consolidated balance sheets. The Partnership values inventories at the lower of cost or market. The Partnership's inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

Property, Plant and Equipment

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

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

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

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

Impairment of Long-Lived Assets

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

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

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

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

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

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the

Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. During the year ended December 31, 2013, the Partnership recognized $13.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet, primarily for its unproved acreage in the Chattanooga and New Albany Shales. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three and six months ended June 30, 2014 and 2013.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2013, the Partnership recognized $24.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the New Albany Shale. There were no impairments of proved gas and oil properties recorded by the Partnership for the three and six months ended June 30, 2014 and 2013.

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

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds by the Partnership was 6.0% and 5.9% for the three months ended June 30, 2014 and 2013, respectively, and 5.8% and 6.0% for the six months ended June 30, 2014 and 2013, respectively. The aggregate amount of interest capitalized by the Partnership was $3.1 million and $3.4 million for the three months ended June 30, 2014 and 2013, respectively, and $5.7 million and $6.9 million for the six months ended June 30, 2014 and 2013, respectively.

Intangible Assets

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

The following table reflects the components of intangible assets being amortized at June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013	Estimated Useful Lives In Years
Gross Carrying Amount	$14,344	$ 14,344	13
Accumulated Amortization	(13,517)	(13,381)	
Net Carrying Amount	$827	$ 963	

Amortization expense on intangible assets was $0.1 million for both the three months ended June 30, 2014 and 2013, and $0.2 million for both the six months ended June 30, 2014 and 2013. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2014 - $0.3 million; 2015 - $0.2 million; 2016 - $0.1 million, 2017 - $0.1 million and 2018 - $0.1 million.

Goodwill

At June 30, 2014 and December 31, 2013, the Partnership had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions. No changes in the carrying amount of goodwill were recorded for the three and six months ended June 30, 2014 and 2013.

The Partnership tests goodwill for impairment at each year end by comparing its reporting units' estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership's management must apply judgment in determining the estimated fair value of these reporting units. The Partnership's management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership's assets and the available market data of the industry group. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership's market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership's management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership's industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership's industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise. During the three and six months ended June 30, 2014 and 2013, no impairment indicators arose, and no goodwill impairments were recognized by the Partnership.

Asset Retirement Obligations

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

Income Taxes

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

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the three and six months ended June 30, 2014 and 2013.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of June 30, 2014.

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners, which is determined after the deduction of the general partner's and the preferred unitholders' interests, by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, income (loss) attributable to preferred limited partners and net income (loss) attributable to the General Partner's Class A units. The General Partner's interest in net income (loss) is calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 13), with a priority allocation of net income to the General Partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner's and limited partners' ownership interests.

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

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. Phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plan (see Note 14), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights would result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award's vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. As such, the net income utilized in the calculation of net income (loss) per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss	$(20,521)	$(6,176)	$(31,282)	$(11,553)
Preferred limited partner dividends	(4,424)	(2,071)	(8,823)	(4,028)
Net loss attributable to common limited partners and the general partner	(24,945)	(8,247)	(40,105)	(15,581)
Less: General partner's interest	(2,377)	(1,022)	(4,381)	(1,323)
Net loss attributable to common limited partners	(27,322)	(9,269)	(44,486)	(16,904)
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	$(27,322)	$(9,269)	$(44,486)	$(16,904)

[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 June 30, 2014 and 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 724,000 and 923,000 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 six months ended June 30, 2014 and 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 772,000 and 960,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Weighted average number of common limited partner units - basic	73,900	47,007	67,595	45,499
Add effect of dilutive incentive awards[1]	—	—	—	—

Add effect of dilutive convertible preferred limited partner units and warrants[(2)]	—	—	—	—
Weighted average number of common limited partner units - diluted	73,900	47,007	67,595	45,499

(1) For the three months ended June 30, 2014 and 2013, approximately 724,000 units and 923,000 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 six months ended June 30, 2014 and 2013, approximately 772,000 units and 960,000 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.

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(2) For the three and six months ended June 30, 2014 and 2013, potential common limited partner units issuable upon conversion of the Partnership's Class B preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the three and six months ended June 30, 2014, potential common limited partner units issuable upon conversion of the Partnership's Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the three and six months ended June 30, 2014, potential common limited partner units issuable upon exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

Revenue Recognition

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

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

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Partnership's records and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see "Use of Estimates" for further description). The Partnership had unbilled revenues of $83.3 million and $55.3 million at June 30, 2014 and December 31, 2013, respectively, which were included in accounts receivable within the Partnership's consolidated balance sheets.

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

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as "other comprehensive income (loss)" on the Partnership's consolidated financial statements, and at June 30, 2014, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 8). The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss).

Recently Adopted Accounting Standards

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

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

Recently Issued Accounting Standards

In June 2014, the FASB issued ASU 2014-12, Compensation – Stock Compensation (Topic 718) (“Update 2014-12”). The amendments in Update 2014-12 require that a performance target that affects vesting and that could be achieved after the requisite service period, be treated as a performance condition. As such, the performance target should not be reflected in estimating the grant date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. The amendments in Update 2014-12 are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Earlier adoption is permitted. Entities may apply the amendments in Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The Partnership will adopt the requirements of Update 2014-12 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) (“Update 2014-09”), which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, Property, Plant and Equipment, and intangible assets within the scope of Topic 350, Intangibles – Goodwill and Other) are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The Partnership will adopt the requirements of Update 2014-09 retrospectively upon its effective date of January 1, 2017, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

NOTE 3 – ACQUISITIONS

Rangely Acquisition

On June 30, 2014, the Partnership completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado for approximately $420.0 million in cash, net of purchase price adjustments (the “Rangely Acquisition”). The purchase price was funded through borrowings under the Partnership’s revolving credit facility, the issuance of an additional $100.0 million of its 7.75% senior notes due 2021 (see Note 7) and the issuance of 15,525,000 common limited partner units (see Note 12). The Rangely Acquisition had an effective date of April 1, 2014. The Partnership’s consolidated financial statements reflected the operating results of the acquired business commencing June 30, 2014 with the transaction closing.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $11.5 million of transaction fees which were included with common limited partners’ interests for the six months ended June 30, 2014 on the Partnership’s consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

Assets:	
Prepaid expenses and other	$4,041
Property, plant and equipment	417,264
Total current assets	$421,305
Liabilities:	
Asset retirement obligation	1,305
Total liabilities assumed	1,305
Net assets acquired	$420,000

EP Energy Acquisition

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

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $12.1 million of transaction fees which were included within common limited partners' interests for the year ended December 31, 2013 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

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

Assets:	
Prepaid expenses and other	$5,268
Property, plant and equipment	723,842
Total current assets	$729,110
Liabilities:	
Accounts payable	2,747
Asset retirement obligation	16,728
Total liabilities assumed	19,475
Net assets acquired	$709,635

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 Rangely and EP Energy acquisitions, including the related borrowings, net proceeds from the issuances of debt and issuances of common and preferred units had occurred on January 1, 2013. 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 Rangely and EP Energy acquisitions and related offerings had occurred on January 1, 2013 or the results that will be attained in future periods (in thousands, except per share data; unaudited):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Total revenues and other	$157,613	$148,591	$338,063	$317,366
Net income (loss)	(2,433)	22,624	(2,409)	35,823
Net income (loss) attributable to common limited partners	(9,596)	16,971	(16,190)	25,665
Net income (loss) attributable to common limited partners per unit:				
Basic	$(0.12)	$0.21	$(0.20)	$0.31
Diluted	$(0.12)	$0.20	$(0.20)	$0.31

Other Acquisitions

On May 12, 2014, the Partnership completed the acquisition of certain assets from GeoMet, Inc. (“GeoMet”) (OTCQB: GMET) for approximately $107.0 million in cash with an effective date of January 1, 2014. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

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):

	June 30, 2014	December 31, 2013	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$326,764	$ 320,459	
Pre-development costs	4,724	4,367	
Wells and related equipment	2,792,248	2,164,760	
Total proved properties	3,123,736	2,489,586	
Unproved properties	214,715	211,536	
Support equipment	31,252	23,005	
Total natural gas and oil properties	3,369,703	2,724,127	
Pipelines, processing and compression facilities	43,093	42,949	2 – 40
Rights of way	829	830	20 – 40
Land, buildings and improvements	8,970	9,462	3 – 40
Other	16,992	15,318	3 – 10
	3,439,587	2,792,686	
Less – accumulated depreciation, depletion and amortization	(772,869)	(671,868)	
	$2,666,718	$ 2,120,818	

During the six months ended June 30, 2014, the Partnership recognized $1.6 million of loss on asset disposal primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement. During the three and six months ended June 30, 2013, the Partnership recognized $0.7 million and $1.4 million of loss on asset disposal pertaining to its decision not to drill wells on leasehold property that expired in such periods in Indiana and Tennessee.

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

NOTE 5 – OTHER ASSETS

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

	June 30, 2014	December 31, 2013

Deferred financing costs, net of accumulated amortization of $15,660 and $11,948 at June 30, 2014 and December 31, 2013, respectively	$42,534	$ 35,292
Notes receivable	3,875	3,978
Long-term derivative asset receivable from Drilling Partnerships	947	863
Other	4,160	2,688
	$51,516	$ 42,821

Deferred financing costs are recorded at cost and amortized over the term of the respective debt agreements (see Note 7). Amortization expense of deferred financing costs was $1.9 million and $1.2 million for the three months ended June 30, 2014 and 2013, respectively, and $3.7 million and $2.6 million for the six months ended June 30, 2014 and 2013, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the three and six months ended June 30, 2014, the Partnership recognized $8.3 million of deferred financing costs relating to the amendment to its revolving credit facility in connection with the Rangely Acquisition (see Note 7). During the six months ended June 30, 2013, the Partnership recognized $3.2 million for accelerated amortization of deferred financing costs associated with the retirement of its then-existing term loan facility and a portion of the outstanding indebtedness under its revolving credit facility with a portion of the proceeds from its issuance of its 7.75% senior notes due 2021 (see Note 7). There was no accelerated amortization of deferred financing costs during the three months ended June 30, 2014 and 2013 and during the six months ended June 30, 2014.

At June 30, 2014 and December 31, 2013, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership's consolidated balance sheets. The notes have a maturity date of March 31, 2022, and a 2.25% per annum interest rate. The maturity date of the notes can be extended to March 31, 2027, subject to certain conditions, including an extension fee of 1.0% of the outstanding principal balance. For the three and six months ended June 30, 2014, approximately $23,000 and $46,000 of interest income, respectively, was recognized within other, net on the Partnership's consolidated statements of operations. For the three and six months ended June 30, 2013, there was approximately $25,000 of interest income recognized within other, net on the Partnership's consolidated statements of operations. At June 30, 2014, the Partnership recorded no allowance for credit losses within its consolidated balance sheets based upon payment history and ongoing credit evaluations associated with the notes receivable.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

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

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

The Partnership proportionately consolidates its ownership interest of the asset retirement obligations of its Drilling Partnerships. At June 30, 2014, the Drilling Partnerships had $55.7 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of the Partnership's proportional interest in such liabilities. Under the terms of the respective partnership agreements, the Partnership maintains the right to retain a portion or all of the distributions to the limited partners of its Drilling Partnerships to cover the limited partners' share of the plugging and abandonment costs up to a specified amount per month. As of June 30, 2014, the Partnership withheld approximately $0.7 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. The Partnership's historical practice and continued intention is to retain distributions from the limited partners as the wells within each Drilling Partnership near the end of their useful life. On a partnership-by-partnership basis, the Partnership assesses its right to withhold amounts related to plugging and abandonment costs based on several factors including commodity price trends, the natural decline in the production of the wells, and current and future costs. Generally, the Partnership's intention is to retain distributions from the limited partners as the fair value of the future cash flows of the limited partners' interest approaches the fair value of the future plugging and abandonment cost. Upon the Partnership's decision to retain all future distributions to the limited partners of its Drilling Partnerships, the Partnership will assume the related asset retirement obligations of the limited partners.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Asset retirement obligations, beginning of period	$91,389	$66,386	$89,776	$64,794
Liabilities incurred	7,326	599	7,855	1,244
Liabilities settled	(200)	(216)	(417)	(223)
Accretion expense	1,487	963	2,788	1,917
Asset retirement obligations, end of period	$100,002	$67,732	$100,002	$67,732

The above accretion expense was included in depreciation, depletion and amortization in the Partnership's consolidated statements of operations and the asset retirement obligation liabilities were included within asset retirement obligations in the Partnership's consolidated balance sheets. During the three and six months ended June 30, 2014, the Partnership incurred $6.6 million of future plugging and abandonment liabilities within purchase accounting for the Rangely and GeoMet acquisitions it consummated during the period (see Note 3). During the year ended December 31, 2013, the Partnership incurred $16.7 million of future plugging and abandonment liabilities within purchase accounting for the EP Energy Acquisition it consummated during the period.

NOTE 7 - DEBT

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

	June 30, 2014	December 31, 2013
Revolving credit facility	$581,000	$ 419,000
7.75 % Senior Notes – due 2021	374,530	275,000
9.25 % Senior Notes – due 2021	248,443	248,334
Total debt	1,203,973	942,334
Less current maturities	—	—
Total long-term debt	$1,203,973	$ 942,334

Credit Facility

On June 30, 2014, in connection with the Rangely Acquisition (see Note 3), the Partnership entered into an amendment to its amended and restated credit agreement (as amended, the "Credit Agreement") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a current borrowing base of $825.0 million and a maximum facility amount of $1.5 billion scheduled to mature in July 2018. The Partnership's borrowing base under the revolving credit facility is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.4 million was outstanding at June 30, 2014. The Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by certain of the Partnership's material subsidiaries, and any non-guarantor subsidiaries of the Partnership are minor. Borrowings under the revolving credit facility bear interest, at the Partnership's election, at either an adjusted LIBOR rate plus an applicable margin between 1.50% and 2.75% per annum or the base rate (which is the higher of the bank's prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 0.50% and 1.75% per annum. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At June 30, 2014, the weighted average interest rate on outstanding borrowings under the revolving credit facility was 2.3%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of June 30, 2014. The Credit Agreement also requires the Partnership to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended through December 31, 2014, 4.25 to 1.0 as of the last day of the quarter ending March 31, 2015, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. Based on the definitions contained in the Partnership's Credit Agreement, at June 30, 2014, the Partnership's ratio of current assets to current liabilities was 1.4 to 1.0, and its ratio of Total Funded Debt to EBITDA was 3.7 to 1.0.

Senior Notes

At June 30, 2014, the Partnership had $374.5 million outstanding of its 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"), inclusive of an additional $100.0 million of such notes issued in a private placement transaction on June 2, 2014 at an offering price of 99.5% of par value, yielding net proceeds of approximately $97.5 million. The net proceeds were used to partially fund the Rangely Acquisition (see Note 3). The Partnership issued $275.0 million of its 7.75% Senior Notes in a private placement transaction at par on January 23, 2013. The 7.75% Senior Notes were presented net of a $0.5 million unamortized discount as of June 30, 2014. Interest is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 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 Partnership entered into registration rights agreements with respect to the $100.0 million 7.75% Senior Notes issued in June 2014. Under the registration rights agreements, the Partnership will cause to be filed with the SEC registration statements with respect to offers to exchange the 7.75% Senior Notes for substantially identical notes that are registered under the Securities Act. The Partnership will use reasonable best efforts to cause such exchange offer registration statements to become effective under the Securities Act. In addition, the Partnership will use reasonable best efforts to cause an exchange offer to be consummated not later than 270 days after the issuance of the 7.75% Senior Notes. Under some 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. The Partnership is required to pay additional interest if it fails to comply with its obligations to register the 7.75% Senior Notes within the specified time periods.

At June 30, 2014, the Partnership had $250.0 million of 9.25% senior notes due 2021 ("9.25% Senior Notes"), issued in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million. The net proceeds were used to partially fund the EP Energy Acquisition (see Note 3). The 9.25% Senior Notes were presented net of a $1.6 million unamortized discount as of June 30, 2014. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. 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. On March 28, 2014, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was completed on April 29, 2014.

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

The indentures governing the 9.25% Senior Notes and 7.75% Senior Notes contain covenants, including limitations on 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 June 30, 2014.

Total cash payments for interest by the Partnership were $26.0 million and $3.7 million for the six months ended June 30, 2014 and 2013, respectively.

NOTE 8 – DERIVATIVE INSTRUMENTS

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

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

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership's consolidated balance sheets as the initial value of the options. The Partnership reflected net derivative liabilities on its consolidated balance sheets of $17.7 million and assets of $22.6 million at June 30, 2014 and December 31, 2013, respectively. Of the $14.2 million of net loss in accumulated other comprehensive income on the Partnership's consolidated balance sheet at June 30, 2014, if the fair values of the instruments remain at current market values, the Partnership will reclassify $18.9 million of losses to gas and oil production revenue on its consolidated statement of operations over the next twelve month period as these contracts expire. Aggregate gains of $4.7 million of gas and oil production revenues will be reclassified to the Partnership's consolidated statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future commodity price changes. No amounts were reclassified from other comprehensive income related to derivative instruments entered into during the three and six months ended June 30, 2014. Approximately $0.5 million of derivative loss was reclassified from other comprehensive income related to derivative instruments entered into during the three and six months ended June 30, 2013.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
(Gain) loss reclassified from accumulated other comprehensive income (loss):				
Gas and oil production revenue	$ 9,185	$ (2,286)	$23,228	$(3,279)
Total	$ 9,185	$ (2,286)	$23,228	$(3,279)

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

Offsetting Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Assets Presented in the Consolidated Balance Sheets
As of June 30, 2014			
Current portion of derivative assets	$ 3,324	$ (3,069)	$ 255
Long-term portion of derivative assets	9,439	(6,024)	3,415
Current portion of derivative liabilities	3,004	(3,004)	—
Long-term portion of derivative liabilities	3,915	(3,915)	—
Total derivative assets	$ 19,682	$ (16,012)	$ 3,670
As of December 31, 2013			
Current portion of derivative assets	$ 2,664	$ (773)	$ 1,891
Long-term portion of derivative assets	31,146	(4,062)	27,084
Current portion of derivative liabilities	4,341	(4,341)	—
Long-term portion of derivative liabilities	122	(122)	—
Total derivative assets	$ 38,273	$ (9,298)	$ 28,975

Offsetting Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated	Net Amount of Liabilities Presented in the Consolidated

			Balance Sheets	Balance Sheets
As of June 30, 2014				
Current portion of derivative assets	$ (3,069	)	$ 3,069	$ —
Long-term portion of derivative assets	(6,024	)	6,024	—
Current portion of derivative liabilities	(22,987	)	3,004	(19,983)
Long-term portion of derivative liabilities	(5,335	)	3,915	(1,420)
Total derivative liabilities	$ (37,415	)	$ 16,012	$ (21,403)
As of December 31, 2013				
Current portion of derivative assets	$ (773	)	$ 773	$ —
Long-term portion of derivative assets	(4,062	)	4,062	—
Current portion of derivative liabilities	(10,694	)	4,341	(6,353)
Long-term portion of derivative liabilities	(189	)	122	(67)
Total derivative liabilities	$ (15,718	)	$ 9,298	$ (6,420)

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

In June 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 $11.3 million, which represented their fair value on the date the transactions were initiated and were initially recorded as a derivative asset on the Partnership's consolidated balance sheet. Swaption contract premiums paid are amortized over the period from initiation of the contract through their termination date. For the three months ended June 30, 2013, the Partnership recognized approximately $1.3 million of amortization expense in other, net on the Partnership's consolidated statement of operations related to the swaption contracts.

The Partnership recognized losses of $9.2 million and gains of $2.3 million for the three months ended June 30, 2014 and 2013, respectively, and losses of $23.2 million and gains of $3.3 million for the six months ended June 30, 2014 and 2013, respectively, on settled contracts covering commodity production. These gains and losses were included within gas and oil production revenue in the Partnership's consolidated statements of operations. As the underlying prices and terms in the Partnership's derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the three and six months ended June 30, 2014 and 2013, respectively, for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At June 30, 2014, the Partnership had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset/ (Liability) (in thousands)(2)
2014	30,076,500	$ 4.152	$ (9,117)
2015	51,924,500	$ 4.239	882
2016	45,746,300	$ 4.311	3,003
2017	24,840,000	$ 4.532	3,321
2018	9,360,000	$ 4.619	360
			$ (1,551)

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes	Average Floor and Cap	Fair Value Asset/ (Liability)

		(MMBtu)[1]	(per MMBtu)[1]	(in thousands)[2]
2014	Puts purchased	1,920,000	$ 4.221	$ 310
2014	Calls sold	1,920,000	$ 5.120	(198)
2015	Puts purchased	3,480,000	$ 4.234	1,487
2015	Calls sold	3,480,000	$ 5.129	(616)
				$ 983

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Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset (in thousands)(2)
2014	Puts purchased	900,000	$ 3.800	$ 27
2015	Puts purchased	1,440,000	$ 4.000	385
2016	Puts purchased	1,440,000	$ 4.150	582
				$ 994

Natural Gas – WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Liability (in thousands)(8)
2014	5,400,000	$ (0.110)	$ (306)
			$ (306)

Natural Gas – NGPL Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Liability (in thousands)(9)
2014	2,700,000	$ (0.110)	$ (22)
			$ (22)

Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Liability (in thousands)(3)
2015	96,000	$ 88.550	$ (787)
2016	84,000	$ 85.651	(479)
2017	60,000	$ 83.780	(306)
			$ (1,572)

Natural Gas Liquids – Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(4)
2014	1,260,000	$ 0.303	$ 18
			$ 18

Natural Gas Liquids – Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Liability (in thousands)(5)
2014	6,174,000	$ 0.999	$ (443)
2015	8,064,000	$ 1.016	(403)
			$ (846)

Natural Gas Liquids – Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Liability (in thousands)(6)
2014	756,000	$ 1.308	$ —
2015	1,512,000	$ 1.248	(58)
			$ (58)

Natural Gas Liquids – Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Liability (in thousands)(7)
2014	756,000	$ 1.323	$ (16)
2015	1,512,000	$ 1.263	(69)
			$ (85)

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Liability (in thousands)(3)
2014	591,000	$ 95.599	$ (4,471)
2015	1,095,000	$ 90.160	(7,207)
2016	777,000	$ 87.785	(2,802)
2017	132,000	$ 83.305	(734)
			$ (15,214)

Crude Oil – Costless Collar

Production Period Ending December 31,	Option Type	Volumes (Bbl)(1)	Average Floor and Cap (per Bbl)(1)	Fair Value Asset/ (Liability) (in thousands)(3)
2014	Puts purchased	20,580	$ 84.169	$ 5
2014	Calls sold	20,580	$ 113.308	(35)

2015	Puts purchased	29,250	$83.846		47
2015	Calls sold	29,250	$110.654		(91)
				$	(74)
			Total net liability	$	(17,733)

(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.
(6) Fair value based on forward Mt. Belvieu butane prices, as applicable.
(7) Fair value based on forward Mt. Belvieu iso butane prices, as applicable
(8) Fair value based on forward WAHA natural gas prices, as applicable
(9) Fair value based on forward NGPL natural gas prices, as applicable

At June 30, 2014, the Partnership had net cash proceeds of $1.3 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.

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 June 30, 2014, net unrealized derivative assets of $1.0 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At June 30, 2014, 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.

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Information for assets and liabilities measured at fair value at June 30, 2014 and December 31, 2013 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
As of June 30, 2014				
Derivative assets, gross				
Commodity swaps	$ —	$16,814	$ —	$16,814
Commodity basis swaps	—	25	—	25
Commodity puts	—	994	—	994
Commodity options	—	1,849	—	1,849
Total derivative assets, gross	—	19,682	—	19,682
Derivative liabilities, gross				
Commodity swaps	—	(36,123)	—	(36,123)
Commodity basis swaps	—	(352)	—	(352)
Commodity options	—	(940)	—	(940)
Total derivative liabilities, gross	—	(37,415)	—	(37,415)
Total derivatives, fair value, net	$ —	$(17,733)	$ —	$(17,733)

	Level 1	Level 2	Level 3	Total
As of December 31, 2013				
Derivative assets, gross				
Commodity swaps	$ —	$33,594	$ —	$33,594
Commodity puts	—	1,374	—	1,374
Commodity options	—	3,305	—	3,305
Total derivative assets, gross	—	38,273	—	38,273
Derivative liabilities, gross				
Commodity swaps	—	(14,624)	—	(14,624)
Commodity options	—	(1,094)	—	(1,094)
Total derivative liabilities, gross	—	(15,718)	—	(15,718)
Total derivatives, fair value, net	$ —	$22,555	$ —	$22,555

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 June 30, 2014 and December 31, 2013, which consists of its Senior Notes and outstanding borrowings under its revolving credit facility (see Note 7), were $1,244.3 million and $938.6 million, respectively, compared with the carrying amounts of $1,204.0 million and $942.3 million, respectively. At June 30, 2014 and December 31, 2013, the carrying values 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 were categorized as Level 3 values.

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 six months ended June 30, 2014 and 2013 were as follows (in thousands):

	Three Months Ended June 30,			
	2014		2013	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$7,326	$7,326	$599	$599
Total	$7,326	$7,326	$599	$599

	Six Months Ended June 30,			
	2014		2013	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$7,855	$7,855	$1,244	$1,244
Total	$7,855	$7,855	$1,244	$1,244

Management estimates the fair value of the Partnership's long-lived assets in connection with reviewing these assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, using estimates, assumptions and judgments regarding such events or circumstances. For the year ended December 31, 2013, the Partnership recognized $38.0 million of impairment of long-lived assets which were defined as a Level 3 fair value measurements (see Note 2 – Impairment of Long-Lived Assets). No impairments were recognized during the three and six months ended June 30, 2014 and 2013.

During the three months ended June 30, 2014, the Partnership completed the Rangely Acquisition and the GeoMet acquisition (see Note 3). During the year ended December 31, 2013, the Partnership completed the acquisition of certain oil and gas assets from EP Energy (see Note 3). The fair value measurements of assets acquired and liabilities assumed for these acquisitions are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The estimated fair values of the assets acquired and liabilities assumed in the Rangely Acquisition and the GeoMet acquisition as of the respective acquisition dates, which are reflected in the Partnership's consolidated balance sheet as of June 30, 2014, are subject to change as the final valuations have not yet been completed, and such changes could be material. 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 valuations 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 a 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 Partnerships' revenues 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 and gas gathering services in the Appalachian Basin in the northwest region 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 both the three months ended June 30, 2014 and 2013, $0.1 million of gathering fees were paid by the Partnership to APL. For both the six months ended June 30, 2014 and 2013, $0.2 million of gathering fees were paid by the Partnership to APL.

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 June 30, 2014, 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 certain of the Drilling Partnerships to the benefit of the investor partners until they have received specified returns, typically 10% to 12% per year determined on a cumulative basis, over a specific period, typically the first five to eight years, in accordance with the terms of the partnership agreements. For the three months ended June 30, 2014 and 2013, $0.4 million and $2.1 million, respectively, and $3.8 million and $4.3 million for the six months ended June 30, 2014 and 2013, 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.

In connection with the EP Energy Acquisition (see Note 3), the Partnership acquired certain long-term annual firm transportation obligations. Estimated fixed and determinable portions of the Partnership's firm transportation obligations as of June 30, 2014 were as follows: 2014 - $4.4 million; 2015 $8.6 million; 2016 $2.1 million; and 2017 to 2018   none.

As of June 30, 2014, the Partnership is committed to expend approximately $36.4 million, principally on drilling and completion expenditures.

Legal Proceedings

The Partnership is 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

In May 2014, in connection with the closing of the Rangely Acquisition (see Note 3), the Partnership issued 15,525,000 of its common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of $19.90 per unit, yielding net proceeds of approximately $297.5 million. The units were registered under the Securities Act of 1933, as amended (the "Securities Act"), pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

In March 2014, the Partnership issued 6,325,000 of its common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of $21.18 per unit, yielding net proceeds of approximately $129.1 million. The units were registered under the Securities Act, pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

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.

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 (see Note 3), the Partnership sold an aggregate of 14,950,000 of its common limited partner units (including 1,950,000 units pursuant to an over-allotment option) 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 agreement with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution agreement, the Partnership could sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. During the year ended December 31, 2013, the Partnership issued 309,174 common limited partner units under the equity distribution program for net proceeds of $6.9 million, net of $0.4 million in commissions and other offering costs paid. The Partnership utilized the net proceeds from the sale to repay borrowings outstanding under its revolving credit facility. The Partnership terminated the equity distribution agreement effective December 27, 2013.

NOTE 13 – CASH DISTRIBUTIONS

In January 2014, the Partnership's board of directors approved the modification of its cash distribution payment practice to a monthly cash distribution program beginning for the month of January 2014, whereby it would distribute all of its available cash (as defined in the partnership agreement) for that month to its unitholders within 45 days from the month end. Prior to that, the partnership paid quarterly cash distributions within 45 days from the end of each calendar quarter. 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.

Distributions declared by the Partnership for the period from January 1, 2013 through June 30, 2014 were as follows (in thousands, except per unit amounts):

Date Cash Distribution Paid	For Quarter/Month Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners	Total Cash Distribution To Preferred Limited Partners	Total Cash Distribution to the General Partner's Class A Units
May 15, 2013	March 31, 2013	$ 0.5100	$ 22,428	$ 1,957	$ 946
August 14, 2013	June 30, 2013	$ 0.5400	$ 32,097	$ 2,072	$ 1,884
November 14, 2013	September 30, 2013	$ 0.5600	$ 33,291	$ 4,248	$ 2,443
February 14, 2014	December 31, 2013	$ 0.5800	$ 34,489	$ 4,400	$ 2,891
March 17, 2014	January 31, 2014	$ 0.1933	$ 12,718	$ 1,467	$ 1,055
April 14, 2014	February 28, 2014	$ 0.1933	$ 12,719	$ 1,466	$ 1,055
May 15, 2014	March 31, 2014	$ 0.1933	$ 12,719	$ 1,466	$ 1,054
June 13, 2014	April 30, 2014	$ 0.1933	$ 15,752	$ 1,466	$ 1,279

July 15, 2014	May 31, 2014	$ 0.1933	$ 15,752	$ 1,466	$ 1,279

On July 24, 2014, the Partnership declared a monthly distribution of $0.1966 per common unit for the month of June 2014. The $18.9 million distribution, including $1.4 million and $1.5 million to the general partner and preferred limited partners, respectively, will be paid on August 14, 2014 to holders of record as of August 6, 2014.

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 as well as 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 June 30, 2014, the Partnership had 2,368,257 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 158,063 phantom units, restricted units and unit options available for grant.

In the case of awards held by eligible employees, following a "change in control", as defined in the 2012 LTIP, 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. Upon a change in control, all unvested awards held by directors will immediately vest in full.

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 four anniversaries of the date of grant. Of the phantom units outstanding under the 2012 LTIP at June 30, 2014, 329,925 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at June 30, 2014 include DERs. During the three months ended June 30, 2014 and 2013, the Partnership paid $0.4 million and $0.5 million, respectively, with respect to the 2012 LTIP's DERs. During the six months ended June 30, 2014 and 2013, the Partnership paid $1.1 million and $1.0

million, respectively, with respect to the 2012 LTIP's DERs. These amounts were recorded as reductions of partners' capital on the Partnership's consolidated balance sheets.

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

	Three Months Ended June 30,			
	2014		2013	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of period	812,308	$ 24.35	1,025,261	$ 24.53
Granted	223,523	20.29	8,540	24.09
Vested and issued[(1)]	(131,374)	24.69	(168,994)	24.69
Forfeited	(3,250)	24.80	(18,875)	24.03
Outstanding, end of period[(2)(3)]	901,207	$ 23.29	845,932	$ 24.51
Vested and not yet issued[(4)]	67,975	$ 24.66	32,750	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 1,590		$ 2,231

	Six Months Ended June 30,			
	2014		2013	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of year	839,808	$ 24.31	948,476	$ 24.76
Granted	227,023	20.30	91,790	22.15
Vested and issued[(1)]	(146,874)	24.48	(171,459)	24.69
Forfeited	(18,750)	23.00	(22,875)	24.23
Outstanding, end of period[(2)(3)]	901,207	$ 23.29	845,932	$ 24.51
Vested and not yet issued[(4)]	74,850	$ 24.49	32,750	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 3,321		$ 5,284

(1) The intrinsic value of phantom unit awards vested and issued during the three months ended June 30, 2014 and 2013 was $2.5 million and $4.1 million, respectively, and $2.9 million and $4.2 million during the six months ended June 30, 2014 and 2013, respectively.

(2) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2014 was $18.3 million.

(3) There was $0.1 million recognized as liabilities on the Partnership's consolidated balance sheets at the periods ended June 30, 2014 and December 31, 2013, representing 25,432 and 16,084 units, respectively, for the periods ending June 30, 2014 and December 31, 2013, respectively, due to the option of the participants to settle in cash instead of units. The respective weighted average grant date fair values for these units were $21.38 and $22.15 for the periods ending June 30, 2014 and December 31, 2013, respectively.

(4) The intrinsic values of phantom unit awards vested, but not yet issued at June 30, 2014 and 2013 were $1.3 million and $0.8 million, respectively, and $1.5 million and $0.8 million during the six months ended June 30, 2014 and 2013, respectively.

At June 30, 2014, the Partnership had approximately $9.8 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 364,763 unit options outstanding under the 2012 LTIP at June 30, 2014 that will vest within the following twelve months. No cash was received from the exercise of options for the three and six months ended June 30, 2014 and 2013.

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

	Three Months Ended June 30,			
	2014		2013	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	1,472,675	$ 24.66	1,513,500	$ 24.67
Granted	—	—	500	25.35
Exercised [1]	—	—	—	—
Forfeited	(5,625)	24.67	(19,250)	24.68
Outstanding, end of period[2][3]	1,467,050	$ 24.66	1,494,750	$ 24.67
Options exercisable, end of period[4]	734,400	$ 24.67	374,375	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 420		$ 771

	Six Months Ended June 30,			
	2014		2013	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of year	1,482,675	$ 24.66	1,515,500	$ 24.68
Granted	—	—	2,500	22.88
Exercised [1]	—	—	—	—
Forfeited	(15,625)	24.43	(23,250)	24.76
Outstanding, end of period[2][3]	1,467,050	$ 24.66	1,494,750	$ 24.67
Options exercisable, end of period[4]	734,400	$ 24.67	374,375	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 1,033		$ 1,965

(1) No options were exercised during the three and six months ended June 30, 2014 and 2013, respectively.
(2) The weighted average remaining contractual life for outstanding options at June 30, 2014 was 7.9 years.
(3) The aggregate intrinsic value of options outstanding at June 30, 2014 was approximately $100.
(4) The weighted average remaining contractual life for exercisable options at June 30, 2014 was 7.9 years. There were no intrinsic values for options exercisable at June 30, 2014 and 2013.

At June 30, 2014, the Partnership had approximately $1.7 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 June 30,	Six Months Ended

			June 30,	
	2014	2013	2014	2013
Expected dividend yield	—%	7.3 %	—%	6.7 %
Expected unit price volatility	—%	44.0 %	—%	44.0%
Risk-free interest rate	—%	1.1 %	—%	1.1 %
Expected term (in years)	—	6.88	—	6.35
Fair value of unit options granted	$ —	$ 4.91	$—	$4.86

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Gas and oil production:				
Revenues	$104,057	$47,094	$200,302	$93,158
Operating costs and expenses	(41,763)	(19,035)	(78,555)	(34,251)
Depreciation, depletion and amortization expense	(55,531)	(20,580)	(103,560)	(40,276)
Segment income	$6,763	$7,479	$18,187	$18,631
Well construction and completion:				
Revenues	$16,336	$24,851	$65,713	$81,329
Operating costs and expenses	(14,206)	(21,609)	(57,142)	(70,721)
Segment income	$2,130	$3,242	$8,571	$10,608
Other partnership management:(1)				
Revenues	$14,324	$11,381	$26,047	$20,887
Operating costs and expenses	(6,699)	(7,264)	(13,594)	(13,995)
Depreciation, depletion and amortization expense	(2,470)	(1,617)	(4,678)	(3,129)
Segment income	$5,155	$2,500	$7,775	$3,763
Reconciliation of segment income to net loss:				
Segment income:				
Gas and oil production	$6,763	$7,479	$18,187	$18,631
Well construction and completion	2,130	3,242	8,571	10,608
Other partnership management	5,155	2,500	7,775	3,763
Total segment income	14,048	13,221	34,533	33,002
General and administrative expenses(2)	(21,315)	(14,217)	(37,770)	(31,784)
Interest expense(2)	(13,263)	(4,508)	(26,451)	(11,397)
Gain (loss) on asset sales and disposal(2)	9	(672)	(1,594)	(1,374)
Net loss	$(20,521)	$(6,176)	$(31,282)	$(11,553)
Capital expenditures:				
Gas and oil production	$48,809	$66,662	$83,792	$122,435
Other partnership management	4,200	3,133	7,540	4,045
Corporate and other	1,649	1,770	3,223	3,572
Total capital expenditures	$54,658	$71,565	$94,555	$130,052

	June 30, 2014	December 31, 2013
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	$2,725,982	$ 2,170,712
Well construction and completion	23,561	55,031
Other partnership management	56,123	56,493
Corporate and other	75,620	61,564
	$2,881,286	$ 2,343,800

(1) Includes revenues and expenses from well services, gathering and processing, administration and oversight and other, net that do not meet the quantitative threshold for reporting segment information.
(2) Gain (loss) on asset sales and disposal, general and administrative expenses 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 July 24, 2014, the Partnership declared a cash distribution of $0.1966 per common unit for the month of June 2014. The $18.9 million distribution, including $1.4 million and $1.5 million to the general partner and preferred limited partners, respectively, will be paid on August 14, 2014 to holders of record as of August 6, 2014.

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, 2013. 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 ("Drilling Partnerships"), in which we coinvest, to finance a portion of our natural gas, crude oil and natural gas liquid production activities.

Atlas Energy, L.P. ("ATLS"), a publicly traded master-limited partnership (NYSE: ATLS), manages our operations and activities through its ownership of our general partner interest. At June 30, 2014, 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 27.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

FINANCIAL PRESENTATION

Our consolidated balance sheets at June 30, 2014 and December 31, 2013, and the consolidated statements of operations for the three and six months ended June 30, 2014 and 2013 include our accounts and our wholly-owned subsidiaries. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the consolidation of the financial statements. Certain amounts in the prior year's consolidated financial statements have been reclassified to conform to the current year presentation.

SUBSEQUENT EVENTS

Cash Distribution. On July 24, 2014, we declared a cash distribution of $0.1966 per common unit for the month of June 2014. The $18.9 million distribution, including $1.4 million and $1.5 million to the general partner and preferred limited partners, respectively, will be paid on August 14, 2014 to holders of record as of August 6, 2014.

RECENT DEVELOPMENTS

Rangely Acquisition. On June 30, 2014, we completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado for approximately $420.0 million in cash, net of purchase price adjustments (the "Rangely Acquisition"). The purchase price was funded through borrowings under our revolving credit facility, the issuance of an additional $100.0 million of our 7.75% senior notes due 2021 (see "Senior Notes") and the issuance of 15,525,000 common limited partner units (see "Issuance of Units"). The Rangely Acquisition had an effective date of April 1, 2014. Our consolidated financial statements reflect the operating results of the acquired business commencing June 30, 2014.

GeoMet Acquisition. On May 12, 2014, we completed the acquisition of assets from GeoMet, Inc. (“GeoMet”) (OTCQB: GMET) for approximately $107.0 million in cash with an effective date of January 1, 2014. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

Issuance of Common Units. In May 2014, in connection with the closing of the Rangely Acquisition, we issued 15,525,000 of our common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of $19.90 per unit, yielding net proceeds of approximately $297.5 million. The units were registered under the Securities Act of 1933, as amended (the “Securities Act”), pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

In March 2014, we issued 6,325,000 of our common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of $21.18 per unit, yielding net proceeds of approximately $129.1 million. The units were registered under the Securities Act, pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

Cash Distribution Practice. In January 2014, our board of directors approved the modification of our cash distribution payment practice to a monthly cash distribution program beginning for the month of January 2014, whereby the monthly cash distribution will be paid within 45 days from the month end.

CONTRACTUAL REVENUE ARRANGEMENTS

Natural Gas. We market the majority of our natural gas production to gas marketers directly or to third party plant operators who process and market our gas. The sales price of natural gas produced is a function of the market in the area and typically linked to a regional index. The production area and pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline, Transco Leidy Line;
- Mississippi Lime - Southern Star;
- Barnett Shale and Marble Falls- Waha;
- Raton - ANR, Panhandle, and NGPL;
- Black Warrior Basin - Southern Natural; and
- Other regions - primarily the Texas Gas Zone SL spot market (New Albany Shale) and the Cheyenne Hub spot market (Niobrara).

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 hold firm transportation obligations on Colorado Interstate Gas for the benefit of production from the Raton Basin in the New Mexico/Colorado Area. The total of firm transportation held is approximately 82,500 dth/d at a weighted average rate of $0.2575/MMBtu under contracts expiring in 2014 and 2016.

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. The oil and natural gas liquids production of our Rangely assets flows into a common carrier pipeline and is sold at prevailing market prices, less applicable transportation and oil quality differentials. 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 to meet pipeline specifications for transport or sale to end users or marketers operating on the receiving pipeline. The resulting plant residue natural gas is sold as indicated above and our NGLs are generally priced and sold using the Mont Belvieu (TX) or Conway (KS) regional processing indices. 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 percentage 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.

Drilling Partnerships. We generally fund a portion of our drilling activities through sponsorship of tax-advantaged 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:

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Well construction and completion. For each well that is drilled by a Drilling Partnership, we receive a 15% 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 $100,000 and $400,000, depending on the type of well drilled, upon initiation of drilling operations, or "spudding" of a well. 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 $1,000 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 the continued development of advanced horizontal and multiple fracturing techniques. 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 decrease. 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 previously had certain agreements which restricted our ability to drill additional wells in certain areas of Pennsylvania, New York and West Virginia, including portions of the Marcellus Shale, which expired on February 17, 2014. Through June 30, 2014, we have established production positions in the following operating areas:

- the Barnett Shale and Marble Falls play, both in the Fort Worth Basin in northern Texas; the Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil;
- 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 EP Energy acquisition during July 2013, as well as the Cedar Bluff area of West Virginia and Virginia, where we established a position following our GeoMet acquisition;
- the Rangely field in northwest Colorado, a mature tertiary CO_2 flood with low-decline oil production, where we have a 25% non-operated net working interest position following our acquisition on June 30, 2014 (see "Recent Developments");

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- 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
- our 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; 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 and the number of wells we turned in line, both gross and for our interest, during the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Gross wells drilled:				
Barnett/Marble Falls	26	17	52	31
Mississippi Lime/Hunton	12	8	16	13
Total	38	25	68	44
Net wells drilled(1):				
Barnett/Marble Falls	18	13	36	26
Mississippi Lime/Hunton	6	2	7	6
Total	24	15	43	32
Gross wells turned in line:				
Marcellus Shale	—	—	—	1
Barnett/Marble Falls	23	10	49	37
Mississippi Lime/Hunton	6	9	11	10
Total	29	19	60	48
Net wells turned in line(1):				
Marcellus Shale	—	—	—	1
Barnett/Marble Falls	20	10	37	34
Mississippi Lime/Hunton	2	6	4	6
Total	22	16	41	41

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in our Drilling Partnerships.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes and production per day for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Production:(1)(2)(3)				
Appalachia:				
Natural gas (MMcf)	3,450	2,795	7,154	5,636
Oil (000's Bbls)	35	26	73	51
Natural gas liquids (000's Bbls)	4	—	7	—
Total (MMcfe)	3,687	2,950	7,630	5,942
Coal-bed Methane:				
Natural gas (MMcf)	10,871	—	20,625	—
Oil (000's Bbls)	—	—	—	—
Natural gas liquids (000's Bbls)	—	—	—	—
Total (MMcfe)	10,871	—	20,625	—
Barnett/Marble Falls:				
Natural gas (MMcf)	5,434	6,043	10,645	11,989
Oil (000's Bbls)	112	78	187	149
Natural gas liquids (000's Bbls)	251	250	483	480
Total (MMcfe)	7,614	8,014	14,663	15,763
Mississippi Lime/Hunton:				
Natural gas (MMcf)	576	362	1,104	790
Oil (000's Bbls)	40	10	67	13
Natural gas liquids (000's Bbls)	49	22	93	44
Total (MMcfe)	1,111	559	2,063	1,134
Other operating areas:				
Natural gas (MMcf)	297	413	603	850
Oil (000's Bbls)	2	2	4	3
Natural gas liquids (000's Bbls)	31	36	61	71
Total (MMcfe)	498	638	997	1,296
Total production:				
Natural gas (MMcf)	20,628	9,613	40,130	19,266
Oil (000's Bbls)	190	117	331	216
Natural gas liquids (000's Bbls)	336	308	644	596
Total (MMcfe)	23,780	12,161	45,977	24,135
Production per day:(1)(2)(3)				
Appalachia:				
Natural gas (Mcfd)	37,916	30,715	39,522	31,139
Oil (Bpd)	388	283	401	280
Natural gas liquids (Bpd)	45	2	37	2
Total (Mcfed)	40,513	32,421	42,152	32,830
Coal-bed Methane:				
Natural gas (Mcfd)	119,465	—	113,948	—
Oil (Bpd)	—	—	—	—
Natural gas liquids (Bpd)	—	—	—	—
Total (Mcfed)	119,465	—	113,948	—

Barnett/Marble Falls:				
Natural gas (Mcfd)	59,711	66,407	58,810	66,239
Oil (Bpd)	1,231	863	1,034	821
Natural gas liquids (Bpd)	2,762	2,748	2,666	2,653
Total (Mcfed)	83,669	88,070	81,009	87,086
Mississippi Lime/Hunton:				
Natural gas (Mcfd)	6,325	3,978	6,100	4,365
Oil (Bpd)	437	115	369	72
Natural gas liquids (Bpd)	543	245	514	244
Total (Mcfed)	12,205	6,138	11,400	6,265
Other operating areas:				
Natural gas (Mcfd)	3,267	4,538	3,334	4,699
Oil (Bpd)	27	20	23	17
Natural gas liquids (Bpd)	340	392	339	393
Total (Mcfed)	5,470	7,012	5,506	7,161
Total production per day:				
Natural gas (Mcfd)	226,684	105,638	221,714	106,442
Oil (Bpd)	2,084	1,281	1,827	1,191
Natural gas liquids (Bpd)	3,689	3,386	3,556	3,292
Total (Mcfed)	261,323	133,641	254,016	133,341

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

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

(3) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas, which comprised 83% of our proved reserves on an energy equivalent basis at December 31, 2013. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for three and six months ended June 30, 2014 and 2013, along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Production revenues (in thousands):[1]				
Appalachia:				
Natural gas revenue	$12,934	$8,039	$23,396	$16,313
Oil revenue	2,930	2,293	5,974	4,471
Natural gas liquids revenue	162	6	238	13
Total revenues	$16,026	$10,338	$29,608	$20,797
Coal-bed Methane:				
Natural gas revenue	$44,606	$—	$87,188	$—
Oil revenue	—	—	—	—
Natural gas liquids revenue	—	—	—	—
Total revenues	$44,606	$—	$87,188	$—
Barnett/Marble Falls:				
Natural gas revenue	$16,427	$17,228	$33,705	$34,680
Oil revenue	10,303	7,178	16,988	13,457
Natural gas liquids revenue	6,350	6,354	12,998	12,615
Total revenues	$33,080	$30,760	$63,691	$60,752
Mississippi Lime/Hunton:				
Natural gas revenue	$2,301	$1,357	$4,826	$3,097
Oil revenue	3,745	966	6,172	1,206
Natural gas liquids revenue	1,825	816	3,766	1,695
Total revenues	$7,871	$3,139	$14,764	$5,998
Other operating areas:				
Natural gas revenue	$1,332	$1,759	$2,675	$3,349
Oil revenue	214	158	341	267
Natural gas liquids revenue	928	940	2,035	1,995
Total revenues	$2,474	$2,857	$5,051	$5,611
Total production revenues:				

Natural gas revenue	$ 77,600	$ 28,383	$ 151,790	$ 57,439
Oil revenue	17,192	10,595	29,475	19,401
Natural gas liquids revenue	9,265	8,116	19,037	16,318
Total revenues	$ 104,057	$ 47,094	$ 200,302	$ 93,158
Average sales price:				
Natural gas (per Mcf):(2)				
Total realized price, after hedge(3)	$ 3.78	$ 3.31	$ 3.92	$ 3.32
Total realized price, before hedge(3)	$ 4.13	$ 3.47	$ 4.40	$ 3.18
Oil (per Bbl):(2)				
Total realized price, after hedge	$ 90.66	$ 90.90	$ 89.12	$ 89.97
Total realized price, before hedge	$ 98.95	$ 92.33	$ 96.49	$ 91.63
Natural gas liquids (per Bbl):(2)				
Total realized price, after hedge	$ 27.60	$ 26.34	$ 29.57	$ 27.39
Total realized price, before hedge	$ 28.93	$ 26.54	$ 32.15	$ 27.60

	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Production costs (per Mcfe):(1) (2)				
Appalachia:				
Lease operating expenses(4)	$ 1.16	$ 1.29	$ 1.07	$ 1.22
Production taxes	0.03	0.06	0.05	0.07
Transportation and compression	0.52	0.53	0.55	0.49
	$ 1.72	$ 1.88	$ 1.67	$ 1.78
Coal-bed Methane:				
Lease operating expenses	$ 1.09	$ —	$ 1.05	$ —
Production taxes	0.35	—	0.34	—
Transportation and compression	0.34	—	0.33	—
	$ 1.77	$ —	$ 1.73	$ —
Barnett/Marble Falls:				
Lease operating expenses	$ 1.50	$ 1.17	$ 1.48	$ 1.04
Production taxes	0.21	0.30	0.27	0.29
Transportation and compression	0.06	0.15	0.07	0.10
	$ 1.77	$ 1.62	$ 1.81	$ 1.43
Mississippi Lime/Hunton:				
Lease operating expenses	$ 1.42	$ 1.75	$ 1.50	$ 1.52
Production taxes	0.14	0.24	0.17	0.26
Transportation and compression	0.29	—	0.30	—
	$ 1.85	$ 1.99	$ 1.97	$ 1.78
Other operating areas:				
Lease operating expenses	$ 0.86	$ 0.83	$ 0.80	$ 0.71
Production taxes	0.19	0.13	0.19	0.12
Transportation and compression	0.19	0.18	0.21	0.18
	$ 1.25	$ 1.14	$ 1.20	$ 1.01
Total production costs:				
Lease operating expenses(4)	$ 1.24	$ 1.21	$ 1.21	$ 1.09
Production taxes	0.24	0.23	0.26	0.23
Transportation and compression	0.27	0.24	0.28	0.20
	$ 1.76	$ 1.68	$ 1.74	$ 1.51

(1) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

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

(3) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the three and six months ended June 30, 2014 and 2013. Including the effect of this subordination, the average realized gas sales price was $3.76 per Mcf ($4.11 per Mcf before the effects of financial hedging) and $2.95 per Mcf ($3.10 per Mcf before the effects of financial hedging) for the three months ended June 30, 2014 and 2013, respectively, and $3.78 per Mcf ($4.26 per Mcf before the effects of financial hedging) and $2.98 per Mcf ($2.85 per Mcf before the effects of financial hedging) for the six months ended June 30, 2014 and 2013, respectively.

(4) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for the three and six months ended June 30, 2014 and 2013. Including the effects of these costs, Appalachia lease operating expenses were $1.17 per Mcfe

($1.73 per Mcfe for total production costs) and $0.83 per Mcfe ($1.43 per Mcfe for total production costs) for the three months ended June 30, 2014 and 2013, respectively, and $0.86 per Mcfe ($1.46 per Mcfe for total production costs) and $0.84 per Mcfe ($1.40 per Mcfe for total production costs) for the six months ended June 30, 2014 and 2013, respectively. Including the effects of these costs, total lease operating expenses were $1.24 per Mcfe ($1.76 per Mcfe for total production costs) and $1.10 per Mcfe ($1.57 per Mcfe for total production costs) for the three months ended June 30, 2014 and 2013, respectively, and $1.17 per Mcfe ($1.71 per Mcfe for total production costs) and $1.00 per Mcfe ($1.42 per Mcfe for total production costs) for the six months ended June 30, 2014 and 2013, respectively.

Three Months Ended June 30, 2014 Compared with the Three Months Ended June, 2013. Total production revenues were $104.1 million for the three months ended June 30, 2014, an increase of $57.0 million from $47.1 million for the three months ended June 30, 2013. This increase principally consisted of a $44.6 million increase attributable to the newly acquired coal-bed methane assets, a $5.7 million increase attributable to the Appalachia assets due primarily to the Marcellus and Utica Shale wells drilled, and a $4.8 million increase attributable to the Mississippi Lime/Hunton, and a $2.3 million increase attributable to the Barnett Shale/Marble Falls operations.

Total production costs were $41.8 million, an increase of $22.8 million from $19.0 million for the three months ended June 30, 2013. This increase consisted of a $19.2 million increase attributable to production costs associated with the newly acquired coal-bed methane assets, a $1.3 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships, and a $2.2 million increase primarily attributable to new well connections, consisting of $0.9 million attributable to the Mississippi Lime/Hunton assets, $0.8 million attributable to Appalachia operations, and $0.5 million attributable to the Barnett Shale/Marble Falls assets. Total production costs per Mcfe increased to $1.76 per Mcfe for the three months ended June 30, 2014 from $1.68 per Mcfe for the comparable prior year period primarily as a result of the increases in our oil and natural gas liquids production. In general, production costs per Mcfe related to oil and natural gas liquids production are higher than production costs per Mcfe for dry natural gas production.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June, 2013. Total production revenues were $200.3 million for the six months ended June 30, 2014, an increase of $107.1 million from $93.2 million for the six months ended June 30, 2013. This increase principally consisted of a $87.2 million increase attributable to the newly acquired coal-bed methane assets and a $20.5 million increase primarily attributable to new wells drilled, consisting of $8.8 million attributable to the Mississippi Lime/Hunton, $8.8 million attributable to the Appalachia assets, and $2.9 million attributable to the Barnett Shale/Marble Falls operations.

Total production costs were $78.6 million, an increase of $44.3 million from $34.3 million for the six months ended June 30, 2013. This increase consisted of a $35.6 million increase attributable to production costs associated with the newly acquired coal-bed methane assets and a $8.6 million increase primarily attributable to new well connections, consisting of $4.0 million attributable to the Barnett Shale/Marble Falls assets, $2.2 million attributable to Appalachia operations, and $2.0 million attributable to the Mississippi Lime/Hunton assets. Total production costs per Mcfe increased to $1.74 per Mcfe for the six months ended June 30, 2014 from $1.51 per Mcfe for the comparable prior year period primarily as a result of the increases in our oil and natural gas liquids production.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling Partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table presents the amounts of drilling partnership investor capital raised and deployed (in thousands), as well as the number of gross and net development wells we drilled for our Drilling Partnerships during the three and six months ended June 30, 2014 and 2013. There were no exploratory wells drilled during the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Drilling partnership investor capital:				
Raised	$ 1,555	$ 3,000	$ 1,555	$ 3,000
Deployed	$ 16,336	$ 24,851	$ 65,713	$ 81,329
Gross partnership wells drilled:				
Barnett/Marble Falls	9	7	32	7
Mississippi Lime/Hunton	8	8	11	9
Total	17	15	43	16
Net partnership wells drilled:				
Barnett/Marble Falls	9	3	20	3
Mississippi Lime/Hunton	8	8	11	9
Total	17	11	31	12

Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for Drilling Partnerships we sponsor. The following table sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Average construction and completion:				
Revenue per well	$ 2,364	$ 2,681	$ 2,934	$ 4,595
Cost per well	2,056	2,331	2,551	3,996
Gross profit per well	$ 308	$ 350	$ 383	$ 599
Gross profit margin	$ 2,130	$ 3,242	$ 8,571	$ 10,608
Partnership net wells associated with revenue recognized(1):				
Appalachia:				
Marcellus Shale	—	1	—	6
Utica	—	2	1	2
Barnett/Marble Falls	4	2	15	2
Mississippi Lime/Hunton	3	5	6	8
Total	7	10	22	18

(1) Consists of Drilling Partnership net wells for which well construction and completion revenue was recognized on a percentage of completion basis.

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013. Well construction and completion segment margin was $2.1 million for the three months ended June 30, 2014, a decrease of $1.1 million from $3.2 million for the three months ended June 30, 2013. This decrease consisted of a $0.8 million decrease related to a lower number of wells recognized for revenue within our Drilling Partnerships, and a $0.3 million decrease associated with lower gross profit margin per well. Average revenue and cost per well decreased between periods due primarily to capital deployed for lower cost Marble Falls wells within the Drilling Partnerships during the three months ended June 30, 2014 compared with capital deployed for higher cost Marcellus and Utica Shale wells during the prior year period. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013. Well construction and completion segment margin was $8.6 million for the six months ended June 30, 2014, a decrease of $2.0 million from $10.6 million for the six months ended June 30, 2013. This decrease consisted of a $3.8 million decrease associated with lower gross profit margin per well, partially offset by a $1.8 million increase related to a higher number of wells recognized for revenue within our Drilling Partnerships. Average revenue and cost per well decreased between periods due primarily to capital deployed for lower cost Marble Falls wells within the Drilling Partnerships during the six months ended June 30, 2014 compared with capital deployed for higher cost Marcellus and Utica Shale wells during the prior year period.

Administration and Oversight

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our Drilling Partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the Drilling Partnerships, such as those in the

Marble Falls play and Niobrara Shale, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales.

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013. Administration and oversight fee revenues were $4.2 million for the three months ended June 30, 2014, an increase of $0.8 million from $3.4 million for the three months ended June 30, 2013. This increase was due to increases in the number of wells spud within the current year period compared with the prior year period, particularly within the Marble Falls Shale.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013. Administration and oversight fee revenues were $5.9 million for the six months ended June 30, 2014, an increase of $1.4 million from $4.5 million for the six months ended June 30, 2013. This increase was due to increases in the number of wells spud within the current year period compared with the prior year period, particularly within the Marble Falls and Mississippi Lime Shales.

Well Services

Well service revenue and expenses represent the monthly operating fees we charge and the work our service company performs, including work performed for our Drilling Partnership wells during the drilling and completing phase as well as ongoing maintenance of these wells and other wells for which we serve as operator.

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013. Well services revenues were $6.4 million for the three months ended June 30, 2014, an increase of $1.5 million from $4.9 million for the three months ended June 30, 2013. Well services expenses were $2.4 million for the three months ended June 30, 2014, an increase of $0.1 million from $2.3 million for the three months ended June 30, 2013. The increase in well services revenue is primarily related to the increased utilization of our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls plays by Drilling Partnership wells.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013. Well services revenues were $11.8 million for the six months ended June 30, 2014, an increase of $2.1 million from $9.7 million for the six months ended June 30, 2013. Well services expenses were $4.9 million for the six months ended June 30, 2014, an increase of $0.3 million from $4.6 million for the six months ended June 30, 2013. The increase in well services revenue is primarily related to the increased utilization of our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls plays by Drilling Partnership wells. The increase in well services expense is primarily related to higher labor costs.

Gathering and Processing

Gathering and processing margin includes gathering fees we charge to our Drilling Partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale. Generally, we charge a gathering fee to our Drilling Partnership wells 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 the Drilling Partnerships by approximately 3%.

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013. Our net gathering and processing expense for the three months ended June 30, 2014 and 2013 was consistent at $0.5 million.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013. Our net gathering and processing expense for the six months ended June, 2014 was $0.5 million, a favorable movement of $0.8 million compared with net processing expense of $1.3 million for the six months ended June 30, 2013. This favorable movement was principally due to an increase in gathering fees from the new Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013. Total general and administrative expenses increased to $21.3 million for the three months ended June 30, 2014 compared with $14.2 million for the three months ended June 30, 2013. This increase was primarily due to a $6.0 million increase in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods and a $2.1 million increase in salaries and wages and other corporate activities due to the growth of our business, partially offset by a $1.0 million decrease in non-cash compensation expense.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013. Total general and administrative expenses increased to $37.8 million for the six months ended June 30, 2014 compared with $31.8 million for the six months ended June 30, 2013. This increase was primarily due to a $4.7 million increase in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods and a $4.2 million increase in salaries and wages and other corporate activities due to the growth of our business, partially offset by a $2.9 million decrease in non-cash compensation expense.

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization increased to $58.0 million for the three months ended June 30, 2014 compared with $22.2 million for the comparable prior year period, which was primarily due to a $34.9 million increase in our depletion expense resulting from the acquisitions we consummated during 2013.

Total depreciation, depletion and amortization increased to $108.2 million for the six months ended June 30, 2014 compared with $43.4 million for the comparable prior year period, which was primarily due to a $63.3 million increase in our depletion expense resulting from the acquisitions we consummated during 2013.

The following table presents a summary of our depreciation, depletion and amortization expense and our depletion expense per Mcfe for our operations for the respective periods (in thousands, except for per Mcfe data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Depreciation, depletion and amortization:				
Depletion expense	$55,531	$20,580	$103,560	$40,276
Depreciation and amortization expense	2,470	1,617	4,678	3,129
	$58,001	$22,197	$108,238	$43,405
Depletion expense:				
Total	$55,531	$20,580	$103,560	$40,276
Depletion expense as a percentage of gas and oil production revenue	53 %	44 %	52 %	43 %
Depletion per Mcfe	$2.34	$1.69	$2.25	$1.67

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties.

For the three months ended June 30, 2014, depletion expense was $55.5 million, an increase of $34.9 million compared with $20.6 million for the three months ended June 30, 2013. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues increased to 53% for the three months ended June 30, 2014, compared with 44% for the three months ended June 30, 2013, which was primarily due to an increase in the depletion expense associated with the increased oil and natural gas liquids volumes resulting from our drilling program. Depletion expense per Mcfe increased to $2.34 for the three months ended June 30, 2014, compared to $1.69 for the prior year comparable period primarily due to an increase in the depletion expense associated with our oil and natural gas liquids wells drilled between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

For the six months ended June 30, 2014, depletion expense was $103.6 million, an increase of $63.3 million compared with $40.3 million for the six months ended June 30, 2013. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues increased to 52% for the six months ended June 30, 2014, compared with 43% for the six months ended June 30, 2013, which was primarily due to an increase in the depletion expense associated with the increased oil and natural gas liquids volumes resulting from our drilling program. Depletion expense per Mcfe increased to $2.25 for the three months ended June 30, 2014, compared to $1.67 for the prior year comparable period primarily due to an increase in the depletion expense associated with our oil and natural gas liquids wells drilled between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

Interest Expense

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013. Interest expense for the three months ended June 30, 2014 was $13.3 million as compared with $4.5 million for the comparable prior year period. The $8.8 million increase consisted of a $5.8 million increase associated with the June 2013 issuance of our 9.25% senior notes due 2021, a $0.6 million increase associated with the June 2014 issuance of an additional $100.0 million of our 7.75% senior notes due 2021, a $1.5 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility net of capitalized interest amounts and a $0.9 million increase associated with amortization of deferred financing costs.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013. Interest expense for the six months ended June 30, 2014 was $26.5 million as compared with $11.4 million for the comparable prior year period. The $15.1 million increase consisted of a $11.6 million increase associated with the June 2013 issuance of our 9.25% senior notes due 2021, a $1.3 million increase associated with a full quarter's impact of the January 2013 issuance of our 7.75% senior notes due 2021, a $0.6 million increase associated with the June 2014 issuance of an additional $100.0 million of our 7.75% senior notes due 2021, a $3.5 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility net of capitalized interest amounts, partially offset by a $1.9 million decrease associated with amortization of deferred financing costs. The decrease in amortization associated with deferred financing costs was primarily related to the accelerated amortization associated with the retirement of our then-existing term loan credit facility and the reduction in our revolving credit facility borrowing base subsequent to our issuance of the 7.75% senior notes due 2021 in the prior year period.

Loss on Asset Sales and Disposal

Three Months Ended June 30, 2014 Compared with the Three Months Ended June 30, 2013. During the three months ended June 30, 2014 and 2013, we recognized gains on asset sales and disposals of $9,000 and losses on asset sales and disposals of $0.7 million, respectively. The $0.7 million loss on asset disposal for the three months ended June 30, 2013 pertained to management's decision not to drill wells on leasehold property that expired in the New Albany and Chattanooga Shales during the period.

Six Months Ended June 30, 2014 Compared with the Six Months Ended June, 2013. During the six months ended June 30, 2014 and 2013, we recognized losses on asset sales and disposals of $1.6 million and $1.4 million, respectively. The $1.6 million loss on asset sales and disposal for the six months ended June 30, 2014 was primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement. The $1.4 million loss on asset disposal for the six months ended June 30, 2013 pertained to management's decision not to drill wells on leasehold property that expired in the New Albany and Chattanooga Shales during the period.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary sources of liquidity are cash generated from operations, capital raised through our Drilling Partnerships, and borrowings under our credit facility (see "Credit Facility"). Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and distributions to our limited partners and general partner. In general, we expect to fund:

- Cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- Expansion capital expenditures and working capital deficits through cash generated from operations, additional borrowings and capital raised through Drilling Partnerships; and
- Debt principal payments through additional borrowings as they become due or by the issuance of additional common units or asset sales.

We rely on cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve month period. However, we are subject to business, operational and other risks that could adversely affect our cash flow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units, the sale of assets and other transactions.

Cash Flows – Six Months Ended June 30, 2014 Compared with the Six Months Ended June 30, 2013

Net cash provided by operating activities of $45.0 million for the six months ended June 30, 2014 represented a favorable movement of $76.9 million from net cash used in operating activities of $31.9 million for the comparable prior year period. The $76.9 million favorable movement in net cash provided by operating activities resulted from a $40.3 million favorable movement in net income excluding non-cash items and a $36.6 million favorable movement in working capital. The $40.3 million favorable movement in net income excluding non-cash items consisted principally of a $51.0 million increase in operating cash flow from the EP Energy assets, which were acquired in July 2013, partially offset by a $17.6 million increase in cash interest expense principally due to our senior note offerings in July 2013 and June 2014. The $36.6 million favorable movement in working capital was principally due to a $51.9 million favorable movement in accounts payable and accrued liabilities, partially offset by a $15.3 million unfavorable movement in accounts receivable, prepaid expenses and other. The $51.9 million favorable movement in accounts payable and accrued liabilities was primarily due to a favorable movement in accounts payable due to the timing of payments and the growth of our business during the six months ended June 30, 2014 compared with the six months ended June 30, 2013. The $15.3 million unfavorable movement in accounts receivable, prepaid expenses and other was principally due to an unfavorable movement in accounts receivable due to the timing of cash receipts during the six months ended June 30, 2014 compared with the six months ended June 30, 2013.

Net cash used in investing activities of $612.2 million for the six months ended June 30, 2014 represented an unfavorable movement of $478.1 million from net cash used in investing activities of $134.1 million for the comparable prior year period. This unfavorable movement was primarily due to an increase in net cash paid for acquisitions relating to the Rangely and GeoMet acquisitions, partially offset by a decrease in capital expenditures. See further discussion of capital expenditures under "Capital Requirements".

Net cash provided by financing activities of $569.3 million for the six months ended June 30, 2014 represented a favorable movement of $383.5 million from net cash provided by financing activities of $185.8 million for the comparable prior year period. This movement was principally due to a $589.0 million increase in borrowings under our revolving credit facility in the current period compared with the prior year period and a $106.2 million increase in net proceeds from the issuance of our common limited partner units in the current period compared with the prior year period, partially offset by a $170.3 million unfavorable movement in net proceeds from our issuance of long-term debt in the current period compared with the prior year period, an unfavorable movement of $75.6 million due to more repayments under our revolving credit facility in the current period compared with the prior year period, an increase of $57.1 million in cash distributions paid and a $8.7 million unfavorable movement in deferred financing costs, distribution equivalent rights and other in the current period compared with the prior year period. The gross amount of borrowings and repayments under our revolving credit facility included within net cash provided by financing activities, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under our revolving credit facility, and payments, which generally occur throughout the period and increase borrowings under our revolving credit facility, which is generally common practice for our industry.

Capital Requirements

Our capital requirements consist primarily of:

maintenance capital expenditures — oil and gas assets naturally decline in future periods and, as such, we recognize the estimated capitalized cost of stemming such decline in production margin for the purpose of stabilizing our distributable cash flow and cash distributions, which we refer to as maintenance capital expenditures. We calculate the estimate of maintenance capital expenditures by first multiplying forecasted future full year production margin by expected aggregate production decline of proved developed producing wells. Maintenance capital expenditures are then the estimated capitalized cost of wells that will generate an estimated first year margin equivalent to the production margin decline, assuming such wells are connected on the first day of the calendar year. We do not incur specific capital expenditures expressly for the purpose of maintaining or increasing production margin, but such amounts are a subset of hypothetical wells we expect to drill in future periods, including Marcellus Shale, Utica Shale, Mississippi Lime and Marble Falls wells, on undeveloped acreage already leased. Estimated capitalized cost of wells included within maintenance capital expenditures are also based upon relevant factors, including historical costs of similar wells and characteristics of each individual well. First year margin from wells included within maintenance capital are also based upon relevant factors, including utilization of public forward commodity exchange prices, current estimates for regional pricing differentials, estimated labor and material rates and other production costs.

Estimates for maintenance capital expenditures in the current year are the sum of the estimate calculated in the prior year plus estimates for the decline in production margin from wells connected during the current year and production acquired through acquisitions; and

- expansion capital expenditures — we consider expansion capital expenditures to be any capital expenditure costs expended that are not maintenance capital expenditures – generally, this will include expenditures to increase, rather than maintain, production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures.

The following table summarizes our maintenance and expansion capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Maintenance capital expenditures	$ 13,100	$ 7,000	$ 23,900	$ 11,000
Expansion capital expenditures	41,558	64,565	70,655	119,052
Total	$ 54,658	$ 71,565	$ 94,555	$ 130,052

During the three months ended June 30, 2014, our $54.7 million of total capital expenditures consisted primarily of $24.7 million for wells drilled exclusively for our own account compared with $29.1 million for the comparable prior year period, $13.8 million of investments in our Drilling Partnerships compared with $25.6 million for the prior year comparable period, $7.3 million of leasehold acquisition costs compared with $19.7 million for the prior year comparable period, and $8.9 million of corporate and other costs compared with $7.8 million for the prior year comparable period, which primarily related to an increase in capitalized interest expense.

During the six months ended June 30, 2014, our $94.6 million of total capital expenditures consisted primarily of $41.8 million for wells drilled exclusively for our own account compared with $65.5 million for the comparable prior year period, $25.0 million of investments in our Drilling Partnerships compared with $37.2 million for the prior year comparable period, $11.3 million of leasehold acquisition costs compared with $13.4 million for the prior year comparable period, and $16.5 million of corporate and other costs compared with $14.0 million for the prior year comparable period, which primarily related to an increase in capitalized interest expense.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisitions in the future, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of June 30, 2014, we are committed to expend approximately $36.4 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our Drilling Partnerships and borrowings under our revolving credit facility.

OFF BALANCE SHEET ARRANGEMENTS

As of June 30, 2014, our off-balance sheet arrangements were limited to our letters of credit outstanding of $4.4 million and commitments to spend $36.4 million related to our drilling and completion and capital expenditures, excluding acquisitions.

CASH DISTRIBUTION POLICY

Our partnership agreement requires that we distribute 100% of available cash to our common and preferred unitholders and general partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments. Our general partner is granted discretion under the partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated.

On January 29, 2014, our board of directors approved a modification to our cash distribution payment practice to a monthly cash distribution program, beginning with January 2014. Monthly cash distributions are paid approximately 45 days following the end of each respective monthly period.

Available cash will generally be distributed: first, 98% to our Class B preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class B preferred unit the greater of $0.40 per quarter and the distribution payable to common unitholders; second, 98% to our Class C preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class C preferred unit the greater of $0.51 per quarter and the distribution payable to common unitholders; thereafter 98% to our common unitholders and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner, if quarterly distributions exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The incentive distribution rights will entitle our general partner to receive the following increasing percentage of cash distributed by us as it reaches certain target distribution levels:

13.0% of all cash distributed in any quarter after each common unit has received $0.46 for that quarter;
23.0% of all cash distributed in any quarter after each common unit has received $0.50 for that quarter; and
48.0% of all cash distributed in any quarter after each common unit has received $0.60 for that quarter.

CREDIT FACILITY

On June 30, 2014, in connection with the Rangely Acquisition (see Recent Developments), we entered into an amendment to our amended and restated credit agreement (as amended, the “Credit Agreement”) with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a current borrowing base of $825.0 million and a maximum facility amount of $1.5 billion scheduled to mature in July 2018. Our borrowing base under the revolving credit facility is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.4 million was outstanding at June 30, 2014. Our obligations under the facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets. Additionally, obligations under the facility are guaranteed by certain of our material subsidiaries, and any of our non-guarantor subsidiaries are minor. Borrowings under the revolving credit facility bear interest, at the our election, at either an adjusted LIBOR rate plus an applicable margin between 1.50% and 2.75% per annum or the base rate (which is the higher of the bank’s prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 0.50% and 1.75% per annum. We are also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on our consolidated statements of operations.

The Credit Agreement contains customary covenants that limit our 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 our assets. We were in compliance with these covenants as of June 30, 2014. The Credit Agreement also requires us to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than 4.50 to 1.0 as of the last day of the quarters ended through December 31, 2014, 4.25 to 1.0 as of the last day of the quarter ending March 31, 2015, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

SENIOR NOTES

At June 30, 2014, we had $374.5 million outstanding of our 7.75% senior unsecured notes due 2021 (“7.75% Senior Notes”), inclusive an additional $100.0 million of such notes in a private placement transaction on June 2, 2014 at an offering price of 99.5% of par value, yielding net proceeds of approximately $97.5 million. The net proceeds were used to partially fund the Rangely Acquisition (see Recent Developments). We issued $275.0 million of our 7.75% Senior Notes in a private placement transaction at par on January 23, 2013. The 7.75% Senior Notes were presented net of a $0.5 million unamortized discount as of June 30, 2014. Interest is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 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.

We entered into registration rights agreements with respect to the $100.0 million 7.75% Senior Notes issued in June 2014. Under the registration rights agreements, we will cause to be filed with the SEC registration statements with respect to offers to exchange the 7.75% Senior Notes for substantially identical notes that are registered under the Securities Act. We will use reasonable best efforts to cause such exchange offer registration statements to become effective under the Securities Act. In addition, we will use reasonable best efforts to cause an exchange offer to be consummated not later than 270 days after the issuance of the 7.75% Senior Notes. Under some 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. We are required to pay additional interest if we fails to comply with our obligations to register the 7.75% Senior Notes within the specified time periods.

At June 30, 2014, we had $250.0 million of 9.25% senior notes due 2021 ("9.25% Senior Notes"), issued in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million. The net proceeds were used to partially fund the EP Energy Acquisition. The 9.25% Senior Notes were presented net of a $1.6 million unamortized discount as of June 30, 2014. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time on or after 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 price 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 a redemption price of 109.250%. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if we experience specific kinds of changes of control, we must offer to repurchase the 9.25% 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 by July 30, 2014. On March 28, 2014, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was completed on April 29, 2014.

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

The indentures governing the 9.25% Senior Notes and 7.75% Senior Notes contain covenants, including limitations on our ability to incur certain liens; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We were in compliance with these covenants as of June 30, 2014.

SECURED HEDGE FACILITY

At June 30, 2014, we 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 our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. 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.

In addition, it will be an event of default under our revolving credit facility if we, as general partner of the Drilling Partnerships, breach an obligation governed by the secured hedge facility, and the effect of such breach is to cause amounts owing under swap agreements governed by the secured hedge facility to become immediately due and payable.

ISSUANCE OF UNITS

In May 2014, in connection with the closing of the Rangely Acquisition (see "Recent Developments"), we issued 15,525,000 of our common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of $19.90 per unit, yielding net proceeds of approximately $297.5 million. The units were registered under the Securities Act of 1933, as amended (the "Securities Act"), pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

In March 2014, we issued 6,325,000 of our common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of $21.18 per unit, yielding net proceeds of approximately $129.1 million. The units were registered under the Securities Act, pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

In July 2013, in connection with the closing of the EP Energy Acquisition, we issued 3,749,986 of our 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 our 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 our common units at an exercise price of $23.10 per unit, subject to adjustments 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.

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 1,950,000 units pursuant to an over-allotment option) in a public offering at a price of $21.75 per unit, yielding net proceeds of approximately $313.1 million. We utilized the net proceeds from the sale to repay the outstanding balance under our revolving credit facility.

In May 2013, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution agreement, we could sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. During the year ended December 31, 2013, we issued 309,174 common limited partner units under the equity distribution program for net proceeds of $6.9 million, net of $0.4 million in commissions and other offering costs paid. We utilized the net proceeds from the sale to repay borrowings outstanding under our revolving credit facility. We terminated the equity distribution agreement effective December 27, 2013.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depletion, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements was included in our Annual Report on Form 10-K for the year ended December 31, 2013, and we summarize our significant accounting policies within our consolidated financial statements included in Note 2 under "Item 1: Financial Statements" included in this report. The critical accounting policies and estimates we have identified are discussed below.

Depreciation and Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets. The cost of property, plant and equipment, less estimated salvage value, is generally depreciated on a straight-line basis over the estimated useful lives of the assets. Useful lives are based on historical experience and are adjusted when changes in planned use, technological advances or other factors indicate that a different life would be more appropriate. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively.

Long-lived assets, other than goodwill and intangibles with infinite lives, generally consist of natural gas and oil properties and pipeline, processing and compression facilities and are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. A long-lived asset, other than goodwill and intangibles with infinite lives, is considered to be impaired when the undiscounted net cash flows expected to be generated by the asset are less than its carrying amount. The undiscounted net cash flows expected to be generated by the asset are based upon our estimates that rely on various assumptions, including natural gas and oil prices, production and operating expenses. Any significant variance in these assumptions could materially affect the estimated net cash flows expected to be generated by the asset. As discussed in "General Trends and Outlook", recent increases in natural gas drilling have driven an increase in the supply of natural gas and put a downward pressure on domestic prices. Further declines in natural gas prices may result in additional impairment charges in future periods.

There were no impairments of proved or unproved gas and oil properties recorded by us for the three and six months ended June 30, 2014 and 2013. During the year ended December 31, 2013, we recognized $38.0 million of asset impairments related to gas and oil properties within property, plant and equipment, net on our consolidated balance sheet for shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. The impairments of proved and unproved properties during the year ended December 31, 2013 related to the carrying amounts of these gas and oil properties being in excess of our estimate of their fair values at December 31, 2013 and our intention not to drill on certain expiring unproved acreage. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions. Additional factors impacting the economic viability of long-lived assets are discussed under “Item 1A: Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2013.

Goodwill and Intangibles with Infinite Lives. Goodwill and intangibles with infinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized if the carrying value of an entity’s reporting units exceeds its estimated fair value.

There were no goodwill impairments recognized by us during the three and six months ended June 30, 2014 and 2013.

Fair Value of Financial Instruments

We have established a hierarchy to measure our financial instruments at fair value, which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. 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.

We use a fair value methodology to value the assets and liabilities for our outstanding derivative contracts. Our commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 fair value measurements.

Liabilities that are required to be measured at fair value on a nonrecurring basis include our asset retirement obligations that are defined as Level 3. Estimates of the fair value of asset retirement obligations are based on discounted cash flows using numerous estimates, assumptions, and judgments regarding the cost, timing of settlement, our credit-adjusted risk-free rate and inflation rates.

During the three months ended June 30, 2014, we completed the Rangely and GeoMet acquisitions. During the year ended December 31, 2013, we completed the EP Energy acquisition. 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 our existing methodology for recognizing an estimated liability for the plugging and abandonment of our gas and oil wells (see "Item 1: Financial Statements - Note 6). These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

Reserve Estimates

Our estimates of proved natural gas, oil and natural gas liquids reserves and future net revenues from them are based upon reserve analyses that rely upon various assumptions, including those required by the SEC, as to natural gas, oil and natural gas liquids, drilling and operating expenses, capital expenditures and availability of funds. The accuracy of these reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates. As discussed in "Item 2: Properties" of our Annual Report on Form 10-K for the year ended December 31, 2013, we engaged Wright and Company, Inc., an independent third-party reserve engineer, to prepare a report of our proved reserves.

Any significant variance in the assumptions utilized in the calculation of our reserve estimates could materially affect the estimated quantity of our reserves. As a result, our estimates of proved natural gas, oil and natural gas liquids reserves are inherently imprecise. Actual future production, natural gas, oil and natural gas liquids prices, revenues, development expenditures, operating expenses and quantities of recoverable natural gas, oil and natural gas liquids reserves may vary substantially from our estimates or estimates contained in the reserve reports and may affect our ability to pay amounts due under our credit facility or cause a reduction in our credit facility. In addition, our proved reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas, oil and natural gas liquids prices, mechanical difficulties, governmental regulation and other factors, many of which are beyond our control. Our reserves and their relation to estimated future net cash flows impact the calculation of impairment and depletion of oil and gas properties. Adjustments to quarterly depletion rates, which are based upon a units of production method, are made concurrently with changes to reserve estimates. Generally, an increase or decrease in reserves without a corresponding change in capitalized costs will have a corresponding inverse impact to depletion expense.

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our gas and oil wells and related facilities. We also recognize a liability for our 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. We also consider the estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability is based on our 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 is discounted using an assumed credit-adjusted risk-free interest rate. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Since there are many variables in estimating asset retirement obligations, we attempt to limit the impact of management’s judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. 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. We have no assets legally restricted for purposes of settling asset retirement obligations. Except for our gas and oil properties, we believe that there are no other material retirement obligations associated with tangible long lived assets.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in interest rates and commodity prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of the market risk sensitive instruments were entered into for purposes other than trading.

General

All of our assets and liabilities are denominated in U.S. dollars, and as a result, we do not have exposure to currency exchange risks.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on June 30, 2014. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties related to our commodity derivative contracts are banking institutions or their affiliates, who also participate in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we currently believe them to be financially viable. We are not aware of any inability on the part of our counterparties to perform under their contracts and believe our exposure to non-performance is remote.

Interest Rate Risk. At June 30, 2014, $581.0 million was outstanding under our revolving credit facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would change our consolidated interest expense for the twelve month period ending June 30, 2015 by $5.8 million.

Commodity Price Risk. Our market risk exposure to commodities is due to the fluctuations in the commodity prices and the impact those price movements have on our financial results. To limit our exposure to changing commodity prices, we use financial derivative instruments, including financial swap and option instruments, to hedge portions of our future production. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under these swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Option instruments are contractual agreements that grant the right, but not the obligation, to purchase or sell commodities at a fixed price for the relevant period.

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our consolidated operating income for the twelve-month period ending June 30, 2015 of approximately $23.8 million.

Realized pricing of our natural gas, oil, and NGL production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production has been volatile and unpredictable for many years. To limit our exposure to changing natural gas, oil and NGL prices, we enter into natural gas and oil swap, put option and costless collar option contracts. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter (“OTC”) futures contracts with qualified counterparties. OTC contracts are generally financial contracts which are settled with financial payments or receipts and generally do not require delivery of physical hydrocarbons. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. Crude oil contracts are based on a West Texas Intermediate ("WTI") index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts have qualified and been designated as cash flow hedges and been recorded at their fair values.

At June 30, 2014, we had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)
2014	30,076,500	$ 4.152
2015	51,924,500	$ 4.239
2016	45,746,300	$ 4.311
2017	24,840,000	$ 4.532
2018	9,360,000	$ 4.619

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)
2014	Puts purchased	1,920,000	$ 4.221
2014	Calls sold	1,920,000	$ 5.120
2015	Puts purchased	3,480,000	$ 4.234
2015	Calls sold	3,480,000	$ 5.129

Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)
2014	Puts purchased	900,000	$ 3.800
2015	Puts purchased	1,440,000	$ 4.000
2016	Puts purchased	1,440,000	$ 4.150

Natural Gas – WAHA Basis Swaps

Production Period Ending	Volumes	Average Fixed Price

December 31,		
	(MMBtu)(1)	(per MMBtu)(1)
2014	5,400,000	$ (0.110)

Natural Gas – NGPL Basis Swaps

Production Period Ending December 31,	Volumes	Average Fixed Price
	(MMBtu)(1)	(per MMBtu)(1)
2014	2,700,000	$ (0.110)

Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

Production Period Ending December 31,	Volumes	Average Fixed Price
	(Bbl)(1)	(per Bbl)(1)
2015	96,000	$ 88.550
2016	84,000	$ 85.651
2017	60,000	$ 83.780

Natural Gas Liquids – Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Gal)[1]
2014	1,260,000	$ 0.303

Natural Gas Liquids – Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]
2014	6,174,000	$ 0.999
2015	8,064,000	$ 1.016

Natural Gas Liquids – Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]
2014	756,000	$ 1.308
2015	1,512,000	$ 1.248

Natural Gas Liquids – Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]
2014	756,000	$ 1.323
2015	1,512,000	$ 1.263

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]
2014	591,000	$ 95.599
2015	1,095,000	$ 90.160
2016	777,000	$ 87.785
2017	132,000	$ 83.305

Crude Oil – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)[1]	Average Floor and Cap (per Bbl)[1]
2014	Puts purchased	20,580	$ 84.169
2014	Calls sold	20,580	$ 113.308
2015	Puts purchased	29,250	$ 83.846
2015	Calls sold	29,250	$ 110.654

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

ITEM 4: CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our general partner’s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our general partner’s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our general partner’s Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2014, our disclosure controls and procedures were effective at the reasonable assurance level.

In June 2014, we acquired certain assets in the Rangely field of northwestern Colorado (see Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations – “Recent Developments”). We are continuing to integrate this system’s historical internal controls over financial reporting with our existing internal controls over financial reporting. This integration may lead to changes in our or the acquired system’s historical internal controls over financial reporting in future fiscal reporting periods.

Other than the previously mentioned item, there have been no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

ITEM 1A: RISK FACTORS

Any acquisitions we complete, including the pending GeoMet and Rangely acquisitions, are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to unitholders.

Any acquisition, including the GeoMet and Rangely acquisitions, involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs;
- an inability to successfully integrate the businesses we acquire;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown environmental and other liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- the incurrence of other significant charges, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic areas; and
- the loss of key purchasers of our production.

Our decision to acquire oil and natural gas properties depends in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

Our 2012 and 2013 acquisitions and our GeoMet and Rangely acquisitions may prove to be worth less than we paid, or provide less than anticipated proved reserves, because of uncertainties in evaluating recoverable reserves, well performance, and potential liabilities as well as uncertainties in forecasting oil and natural gas prices and future development, production and marketing costs.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, development potential, well performance, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Our estimates of future reserves and estimates of future production for our 2012 and 2013 acquisitions and the GeoMet and Rangely acquisitions, are initially based on detailed information furnished by the sellers and subject to review, analysis and adjustment by our internal staff, typically without consulting independent petroleum engineers. Such assessments are inexact and their accuracy is inherently uncertain; our proved reserves estimates may thus exceed actual acquired proved reserves. In connection with our assessments, we perform a review of the acquired properties that we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. As a result of these factors, the purchase price we pay to acquire oil and natural gas properties may exceed the value we realize.

Also, our reviews of acquired properties, including properties that are part of the GeoMet and Rangely acquisitions, are inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition given the time constraints imposed by the applicable acquisition agreement. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor would it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies and potential.

Any production associated with the assets acquired in the Rangely acquisition will decline if the operator’s access to sufficient amounts of carbon dioxide is limited.

Production associated with the assets we acquired in the Rangely acquisition is dependent on CO_2 tertiary recovery operations in the Rangely Field. The crude oil and NGL production from these tertiary recovery operations depends, in large part, on having access to sufficient amounts of CO_2. The ability to produce oil and NGLs from these assets would be hindered if the supply of CO_2 was limited due to, among other things, problems with the Rangely Field’s current CO_2 producing wells and facilities, including compression equipment, or catastrophic pipeline failure. Any such supply limitation could have a material adverse effect on the results of operations and cash flows associated with these tertiary recovery operations. Our anticipated future crude oil and NGL production from tertiary operations is also dependent on the timing, volumes and location of CO_2 injections and, in particular, on the operator’s ability to increase its combined purchased and produced volumes of CO_2 and inject adequate amounts of CO_2 into the proper formation and area within the Rangely Field.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price that we receive for our production could significantly reduce our cash available for distribution and adversely affect our financial condition.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price that we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead price that we receive could significantly reduce our cash available for distribution to our unitholders and adversely affect our financial condition. We use the relevant benchmark price to calculate our hedge positions, and in certain areas, we do not have any commodity derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials, which could adversely affect our results of operations.

ITEM 6: EXHIBITS

Exhibit No.	Description
1.1	Underwriting Agreement, dated May 8, 2014, among Atlas Resource Partners, L.P. and the underwriters named therein [26]
2.1	Purchase and Sale Agreement, dated as of May 6, 2014. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request[14]
2.2	Asset Purchase Agreement, dated as of February 13, 2014, by and among GeoMet, Inc., GeoMet Operating Company, Inc., GeoMet Gathering Company, LLC and ARP Mountaineer Production, LLC. The exhibits and schedules to the Asset Purchase Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted exhibits and schedules will be furnished to the U.S. Securities and Exchange Commission upon request[25]
3.1	Certificate of Limited Partnership of Atlas Resource Partners, L.P.[2]
3.2(a)	Amended and Restated Limited Partnership Agreement of Atlas Resource Partners, L.P.[4]
3.2(b)	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of July 25, 2012[12]
3.2(c)	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of July 31, 2013[6]
3.3	Certificate of Formation of Atlas Resource Partners GP, LLC[2]
3.4	Second Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC[24]
4.1(a)	Indenture dated as of January 23, 2013 among Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the subsidiaries named therein and U.S. Bank National Association[20]
4.1(b)	Supplemental Indenture dated as of June 2, 2014 among Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the subsidiaries named therein and U.S. Bank National Association[29]

4.2(a)	Indenture dated as of July 30, 2013, by and between Atlas Resource Escrow Corporation and Wells Fargo Bank, National Association[22]
4.2(b)	Supplemental Indenture dated as of July 31, 2013, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Bank, National Association[22]
4.3	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class B Preferred Units, dated as of July 25, 2013[12]
4.4	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class C Convertible Preferred Units, dated as of July 31, 2013[6]
4.5	Warrant to Purchase Common Units[6]

Exhibit No.	Description
10.1	Pennsylvania Operating Services Agreement dated as of February 17, 2011 between Chevron North America Exploration and Production (f/k/a Atlas Energy, Inc.), Atlas Energy, L.P. (f/k/a Atlas Pipeline Holdings, L.P.) and Atlas Resources, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.2	Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.3	Amendment No. 1 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of January 6, 2011(5)
10.4	Amendment No. 2 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of February 2, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.5	Transaction Confirmation, Supply Contract No. 0001, under Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated February 17, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.6	Gas Gathering Agreement for Natural Gas on the Legacy Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.7	Gas Gathering Agreement for Natural Gas on the Expansion Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific

	terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission[5]
10.8	Secured Hedge Facility Agreement, among Atlas Resources, LLC, the participating partnerships from time to time party thereto, the hedge providers from time to time party thereto and Wells Fargo Bank, N.A., as collateral agent for the hedge providers[3]
10.9(a)	Second Amended and Restated Credit Agreement dated July 31, 2013 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[6]
10.9(b)	First Amendment to Second Amended and Restated Credit Agreement dated December 6, 2013 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[28]

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Exhibit No.	Description
10.9(c)	Third Amendment to Second Amended and Restated Credit Agreement dated June 30, 2014 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[29]
10.10	2012 Long-Term Incentive Plan of Atlas Resource Partners, L.P. [4]
10.11	Form of Phantom Unit Grant Agreement under 2012 Long-Term Incentive Plan[8]
10.12	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan[8]
10.13	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan[8]
10.14	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011[5]
10.15	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011[5]
10.16	Employment Agreement between Atlas Energy, L.P. and Matthew A. Jones dated as of November 4, 2011[7]
10.17	Employment Agreement between Atlas Energy, L.P. and Daniel Herz dated as of November 4, 2011[23]
10.18	Registration Rights Agreement, dated as of April 30, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein[10]
10.19	Registration Rights Agreement, dated as of July 25, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein[12]
10.20	Registration Rights Agreement, dated as of May 16, 2012, between Atlas Resource Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein[13]
10.21	Registration Rights Agreement dated as of June 2, 2014, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein Wells Fargo Securities, LLC and Deutsche Bank Securities, Inc [29]

10.22	Registration Rights Agreement dated as of July 31, 2013, by and among Atlas Energy, L.P. and Atlas Resource Partners, L.P. [6]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
31.1	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2	Rule 13(a)-14(a)/15(d)-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification
99.1	Voting Agreement, dated as of February 13, 2014, by and among ARP Mountaineer Production, LLC, Atlas Resource Partners, L.P. and each of the persons listed on Annex I thereto[25]
101.INS	XBRL Instance Document[27]
101.SCH	XBRL Schema Document[27]
101.CAL	XBRL Calculation Linkbase Document[27]

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Exhibit No.	Description
101.LAB	XBRL Label Linkbase Document[27]
101.PRE	XBRL Presentation Linkbase Document[27]
101.DEF	XBRL Definition Linkbase Document[27]

(1) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 31, 2013.
(2) Previously filed as an exhibit to our Registration Statement on Form 10, as amended (File No. 1-35317).
(3) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 7, 2012.
(4) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 14, 2012.
(5) Previously filed as an exhibit to Atlas Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.
(6) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 6, 2013
(7) Previously filed as an exhibit to Atlas Energy's Annual Report on Form 10-K for the year ended December 31, 2011.
(8) Previously filed as an exhibit to our Annual Report on Form 10-K filed for the year ended December 31, 2011.
(9) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 21, 2012.
(10) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 1, 2012.
(11) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 10, 2013.
(12) Previously filed as an exhibit to our Current Report on Form 8-K filed on July 26, 2012.
(13) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.
(14) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 7, 2014.
(15) Previously filed as an exhibit to our Current Report on Form 8-K filed on December 26, 2012.
(16) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 11, 2013.
(17) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 17, 2013.
(18) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.
(19) Previously filed as an exhibit to our Current Report on Form 8-K filed on November 27, 2012.
(20) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 25, 2013.
(21) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 14, 2013.
(22) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 2, 2013.
(23) Previously filed as an exhibit to Atlas Energy's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013.
(24) Previously filed as an exhibit to our quarterly report on Form 10-Q for the quarter ended September 30, 2013.
(25) Previously filed as an exhibit to our current report on Form 8-K filed on February 18, 2014.
(26) Previously filed as an exhibit to our current report on Form 8-K filed on May 14, 2014.
(27) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed".
(28) Previously filed as an exhibit to our Annual Report on Form 10-K filed for the year ended December 31, 2013.
(29) Previously filed as an exhibit to our current report on Form 8-K filed on June 3, 2014.

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SIGNATURES

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

ATLAS RESOURCE PARTNERS, L.P.

By: Atlas Resource Partners GP, LLC, its General Partner

Date: August 8, 2014	By: /s/ EDWARD E. COHEN Edward E. Cohen Chairman of the Board and Chief Executive Officer of the General Partner
Date: August 8, 2014	By: /s/ SEAN P. MCGRATH Sean P. McGrath Chief Financial Officer of the General Partner
Date: August 8, 2014	By: /s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback Chief Accounting Officer of the General Partner