UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A

(Amendment No. 1)

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2015

OR

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

Commission file number: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	45-3591625
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
	15275

Park Place Corporate Center One
1000 Commerce Drive, Suite 400
Pittsburgh, Pennsylvania
(Address of principal executive office) (Zip code)
Registrant's telephone number, including area code: (800) 251-0171

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

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

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

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

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

The number of outstanding common limited partner units of the registrant on May 5, 2015 was 87,204,616.

EXPLANATORY NOTE

This Amendment No. 1 on Form 10-Q/A (the “Amendment”) amends Atlas Resource Partners, L.P.’s (the “Partnership”) Quarterly Report on Form 10-Q for the three months ended March 31, 2015, as originally filed with the Securities and Exchange Commission on May 8, 2015 (the “Original Filing”). The Partnership is filing the Amendment solely for the purposes of correcting a scrivener’s error in the certifications filed as Exhibits 31.1, 31.2 and 32.1 to the Original Filing.

This Amendment does not affect any other parts of, or exhibits to, the Original Filing, nor does it reflect events occurring after the date of the Original Filing.

ATLAS RESOURCE PARTNERS, L.P.

INDEX TO QUARTERLY REPORT

ON FORM 10-Q

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	March 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$2,582	$15,247
Accounts receivable	94,150	112,038
Advances to affiliates	21,328	—
Current portion of derivative asset	145,499	141,366
Subscriptions receivable	—	32,398
Prepaid expenses and other	27,856	26,011
Total current assets	291,415	327,060
Property, plant and equipment, net	2,198,436	2,208,171
Goodwill and intangible assets, net	14,271	14,330
Long-term derivative asset	186,718	127,933
Other assets, net	56,736	50,081
	$2,747,576	$2,727,575
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$93,548	$109,049
Advances from affiliates	—	4,271
Liabilities associated with drilling contracts	16,956	40,611
Current portion of derivative payable to Drilling Partnerships	1,526	932
Accrued well drilling and completion costs	42,552	80,404
Accrued interest	11,424	26,452
Distribution payable	12,405	20,876
Accrued liabilities	28,795	56,463
Total current liabilities	207,206	339,058
Long-term debt	1,500,178	1,394,460
Asset retirement obligations	107,899	106,528
Other long-term liabilities	2,663	2,033

Commitments and contingencies		
Partners' Capital:		
General partner's interest	(13,842)	(13,697)
Preferred limited partners' interests	182,968	163,522
Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	600,015	548,586
Accumulated other comprehensive income	159,313	185,909
Total partners' capital	929,630	885,496
	$2,747,576	$2,727,575

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31, 2015	2014
Revenues:		
Gas and oil production	$100,972	$96,245
Well construction and completion	23,655	49,377
Gathering and processing	2,184	4,468
Administration and oversight	1,259	1,729
Well services	6,624	5,479
Gain on mark-to-market derivatives	104,523	—
Other, net	30	47
Total revenues	239,247	157,345
Costs and expenses:		
Gas and oil production	44,220	36,792
Well construction and completion	20,570	42,936
Gathering and processing	2,417	4,413
Well services	2,198	2,482
General and administrative	17,131	16,455
Depreciation, depletion and amortization	41,866	50,237
Total costs and expenses	128,402	153,315
Operating income	110,845	4,030
Interest expense	(25,197)	(13,187)
Loss on asset sales and disposal	(11)	(1,603)
Net income (loss)	85,637	(10,760)
Preferred limited partner dividends	(3,653)	(4,399)
Net income (loss) attributable to common limited partners and the general partner	$81,984	$(15,159)
Allocation of net income (loss) attributable to common limited partners and the general partner:		
Common limited partners' interest	$80,344	$(17,163)
General partner's interest	1,640	2,004
Net income (loss) attributable to common limited partners and the general partner	$81,984	$(15,159)
Net income (loss) attributable to common limited partners per unit:		
Basic	$0.93	$(0.28)
Diluted	$0.91	$(0.28)

Weighted average common limited partner units outstanding:		
Basic	85,505	61,219
Diluted	89,985	61,219

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Three Months Ended	
	March 31,	
	2015	2014
Net income (loss)	$85,637	$(10,760)
Other comprehensive income (loss):		
Changes in fair value of derivative instruments accounted for as cash flow hedges	—	(34,844)
Less: reclassification adjustment for realized (gains) losses of cash flow hedges in net income (loss)	(26,596)	14,043
Total other comprehensive income (loss)	(26,596)	(20,801)
Comprehensive income (loss) attributable to common and preferred limited partners and the general partner	$59,041	$(31,561)

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS’ CAPITAL

(in thousands, except unit data)

(Unaudited)

ral ers’ Interest A		Preferred Limited Partners’ Interest						Common Limited Partners’ Interests		Class C Common Limited Partner Warrants	
		Class B		Class C		Class D					
	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Amount
9,113	$(13,697)	39,654	$983	3,749,986	$85,501	3,200,000	$77,038	85,346,941	$548,586	562,497	$1,176
43	—	—	—	—	—	800,000	19,980	420,586	3,327	—	—
	—	—	—	—	—	—	—	277,307	3,435	—	—
	1,174	—	2	—	100	—	(182)	—	7,433	—	—
	(2,959)	—	(21)	—	(2,112)	—	(1,974)	—	(42,845)	—	—
	—	—	—	—	—	—	—	—	(265)	—	—
	1,640	—	16	—	1,912	—	1,725	—	80,344	—	—
	—	—	—	—	—	—	—	—	—	—	—
3,356	$(13,842)	39,654	$980	3,749,986	$85,401	4,000,000	$96,587	86,044,834	$ 600,015	562,497	$1,176

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Three Months Ended March 31, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$85,637	$(10,760)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	41,866	50,237
Gain on mark-to-market derivatives	(104,523)	—
Loss on asset sales and disposal	11	1,603
Non-cash compensation expense	3,344	2,343
Amortization of deferred financing costs	6,981	1,758
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	38,393	16,111
Accounts payable and accrued liabilities	(82,548)	(38,611)
Net cash provided by (used in) operating activities	(10,839)	22,681
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(42,498)	(39,897)
Net cash paid for acquisitions	(4,602)	—
Other	130	(514)
Net cash used in investing activities	(46,970)	(40,411)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	161,000	162,000
Borrowings under term loan facilities	242,500	—
Repayments under credit facilities	(298,000)	(215,000)
Distributions paid to unitholders	(49,911)	(57,020)
Net proceeds from issuance of common limited partner units	3,327	129,011
Deferred financing costs, distribution equivalent rights and other	(13,772)	(1,124)
Net cash provided by financing activities	45,144	17,867
Net change in cash and cash equivalents	(12,665)	137
Cash and cash equivalents, beginning of year	15,247	1,828
Cash and cash equivalents, end of period	$2,582	$1,965

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

March 31, 2015

(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.

On February 27, 2015, the Partnership's general partner, Atlas Energy Group, LLC ("Atlas Energy Group"; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. ("Atlas Energy"), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as "ATLS"). Atlas Energy Group manages the Partnership's operations and activities through its ownership of the Partnership's general partner interest. Concurrent with Atlas Energy Group's unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. ("Targa"; NYSE: TRGP) and ceased trading. At March 31, 2015, Atlas Energy Group owned 100% of the Partnership's general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 27.5% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2014 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States ("U.S. GAAP") for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management's opinion, all adjustments necessary for a fair presentation of the Partnership's financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2014. Certain amounts in the prior year's financial statements have been reclassified to conform to the current year presentation. The results of operations for the three months ended March 31, 2015 may not necessarily be indicative of the results of operations for the full year ending December 31, 2015.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership's consolidated balance sheets at March 31, 2015 and December 31, 2014 and the consolidated statements of operations for the three months ended March 31, 2015 and 2014 include the accounts of the Partnership and its wholly-owned subsidiaries. Transactions between the Partnership and other ATLS operations have been identified in the consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

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

Use of Estimates

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

The natural gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Differences between estimated and actual amounts are recorded in the following month's financial results. Management believes that the operating results presented for the three months ended March 31, 2015 and 2014 represent actual results in all material respects (see "Revenue Recognition").

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. In evaluating the realizability of accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customers' current creditworthiness, as determined by management's review of the Partnership's customers' credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At March 31, 2015 and December 31, 2014, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $8.1 million and $8.6 million of inventory at March 31, 2015 and December 31, 2014, respectively, which was included within prepaid expenses and other current assets on the Partnership's consolidated balance sheets. The Partnership values inventories at the lower of cost or market. The Partnership's inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

Property, Plant and Equipment

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

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

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

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

Impairment of 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 future prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

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

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

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

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three months ended March 31, 2015 and 2014.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2014, the Partnership recognized $555.7 million of asset impairment related to oil and gas properties within property, plant and equipment, net on its consolidated balance sheet for its Appalachian and mid-continent operations, which was reduced by $82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014. There were no impairments of proved gas and oil properties recorded by the Partnership for the three months ended March 31, 2015 and 2014.

The impairment of proved properties during the year ended December 31, 2014 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, 2014. The estimate of the fair values of these gas and oil properties was impacted by, among other factors, the deterioration of commodity 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 6.1% and 5.6% for the three months ended March 31, 2015 and 2014, respectively. The aggregate amount of interest capitalized by the Partnership was $3.9 million and $2.6 million for the three months ended March 31, 2015 and 2014, respectively.

Intangible Assets

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

The following table reflects the components of intangible assets being amortized at March 31, 2015 and December 31, 2014 (in thousands):

	March 31, 2015	December 31, 2014	Estimated Useful Lives In Years
Gross Carrying Amount	$ 14,344	$ 14,344	13
Accumulated Amortization	(13,712)	(13,653)	
Net Carrying Amount	$ 632	$ 691	

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

Goodwill

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

The Partnership tests goodwill for impairment at each year end by comparing its reporting units' estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership's management must apply judgment in determining the estimated fair value of these reporting units. The Partnership's management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership's assets. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership's market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole.

Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership's management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership's industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership's industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise.

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

Derivative Instruments

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

Asset Retirement Obligations

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

Income Taxes

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

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the three months ended March 31, 2015 and 2014.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2011. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of

March 31, 2015.

Net Income (Loss) Per Common Unit

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

13

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

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

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

	Three Months Ended March 31,	
	2015	2014
Net income (loss)	$ 85,637	$ (10,760)
Preferred limited partner dividends	(3,653)	(4,399)
Net income (loss) attributable to common limited partners and the general partner	81,984	(15,159)
Less: General partner's interest	(1,640)	(2,004)
Net income (loss) attributable to common limited partners	80,344	(17,163)
Less: Net income attributable to participating securities – phantom units[(1)]	(644)	—
Net income (loss) utilized in the calculation of net loss attributable to common limited partners per unit - Basic	$ 79,700	$ (17,163)
Plus: Convertible preferred limited partner dividends	1,928	—
Net income (loss) utilized in the calculation of net loss attributable to common limited partners per unit - Diluted	$ 81,628	$ (17,163)

(1) Net income attributable to common limited partners' ownership interests is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended March 31, 2014, net loss attributable to common limited partners' ownership interest is not allocated to approximately 820,000 phantom units 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 or if converted methods, as applicable. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership’s long-term incentive plan (see Note 14).

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

	Three Months Ended March 31,	
	2015	2014
Weighted average number of common limited partner units - basic	85,505	61,219
Add effect of dilutive incentive awards[1]	691	—
Add effect of dilutive convertible preferred limited partner units and warrants[2]	3,789	—
Weighted average number of common limited partner units - diluted	89,985	61,219

(1) For the three months ended March 31, 2014, 820,000 phantom 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.

(2) For the three months ended March 31, 2014, potential common limited partner units issuable upon conversion of the Partnership's Class B preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. For the three months ended March 31, 2014, potential common limited partner units issuable upon (a) conversion of the Partnership's Class C preferred units and (b) exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. At March 31, 2015, 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. As the Class D preferred units are convertible only upon a change of control event, they are not considered dilutive securities for earnings per unit purposes.

Revenue Recognition

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

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

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

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

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

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

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

The Partnership's gas and oil production operations accrue unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see "Use of Estimates" for further description). The Partnership had unbilled revenues at March 31, 2015 and December 31, 2014 of $53.2 million and $82.3 million, respectively, which were included in accounts receivable within the Partnership's consolidated balance sheets.

Comprehensive Income (Loss)

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

Recently Issued Accounting Standards

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

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

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

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

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

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

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

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, Property, Plant and Equipment, and intangible assets within the scope of Topic 350, Intangibles – Goodwill and Other) are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 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. On April 1, 2015, the FASB tentatively decided to defer the effective date of ASU 2014-09 by one year. As a result, public entities would apply the new revenue standard to annual reporting periods beginning after December 15, 2017, and to interim periods within that reporting period, with early adoption permitted.

NOTE 3 – ACQUISITIONS

Rangely Acquisition

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

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $11.6 million of transaction fees, which were included with common limited partners' interests for the year ended December 31, 2014 on the Partnership's consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred. 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	405,416
Other assets, net	2,888
Total assets acquired	$412,345
Liabilities:	
Accrued liabilities	2,117
Asset retirement obligation	1,305
Total liabilities assumed	3,422
Net assets acquired	$408,923

Other Acquisitions

On November 5, 2014, the Partnership and the general partner's private development subsidiary (the "Development Subsidiary") completed an acquisition of oil and natural gas liquid interests in the Eagle Ford Shale in Atascosa County, Texas from Cima Resources, LLC and Cinco Resources, Inc. (together "Cinco") for $339.2 million, net of purchase price adjustments (the "Eagle Ford Acquisition"). Approximately $179.5 million was paid in cash by the Partnership and $19.7 million was paid by the Development Subsidiary at closing, and approximately $140.0 million was to be paid in four quarterly installments beginning December 31, 2014. On December 31, 2014, the Development Subsidiary made its first installment payment of $35.0 million related to its Eagle Ford Acquisition. Prior to the March 31, 2015 installment, the Partnership, the Development Subsidiary, and Cinco amended the purchase and sale agreement to alter the timing and amount of the quarterly payments beginning with the March 31, 2015 payment and ending December 31, 2015, with no change to the overall purchase price. On March 31, 2015, the Development Subsidiary paid $28.3 million and the Partnership issued $20.0 million of its Class D Preferred Units (see Note 12) to satisfy the second installment related to the Eagle Ford Acquisition. At March 31, 2015, the Partnership's remaining deferred portion of the purchase price was $4.2 million, which consisted of $1.3 million, $1.3 million, and $1.6 million on June 30, 2015, September 30, 2015, and December 31, 2015, respectively. The Partnership's issuance of Class D Preferred Units represents a non-cash transaction for statement of cash flow purposes during the three months ended March 31, 2015.

On May 12, 2014, the Partnership completed the acquisition of certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for approximately $97.9 million in cash, net of purchase price adjustments, with an effective date of January

1, 2014. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2015	December 31, 2014	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$444,035	$441,548	
Pre-development costs	8,912	7,223	
Wells and related equipment	2,981,128	2,962,202	
Total proved properties	3,434,075	3,410,973	
Unproved properties	220,094	217,174	
Support equipment	40,687	37,062	
Total natural gas and oil properties	3,694,856	3,665,209	
Pipelines, processing and compression facilities	50,493	49,462	2 – 40
Rights of way	829	830	20 – 40
Land, buildings and improvements	9,201	9,160	3 – 40
Other	18,055	17,932	3 – 10
	3,773,434	3,742,593	
Less – accumulated depreciation, depletion and amortization	(1,574,998)	(1,534,422)	
	$2,198,436	$2,208,171	

During the three months ended March 31, 2015, the Partnership recognized approximately $11,000 of loss on asset sales and disposals. During the three months ended March 31, 2014, the Partnership recognized $1.6 million of loss on asset sales and disposals primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement.

There were no asset impairments for the three months ended March 31, 2015 and 2014. During the year ended December 31, 2014, the Partnership recognized $555.7 million of asset impairment related to oil and gas properties within property, plant and equipment, net on its consolidated balance sheet for its Appalachian and mid-continent operations, which was reduced by $82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014. This impairment 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, 2014. The estimates of fair values of these gas and oil properties were impacted by, among other factors, the deterioration of commodity prices at the date of measurement.

During the three months ended March 31, 2015 and 2014, the Partnership recognized $16.3 million and $13.4 million, respectively, of non-cash property, plant and equipment additions, which were included within the changes in accounts payable and accrued liabilities on the Partnership's consolidated statements of cash flows.

NOTE 5 – OTHER ASSETS

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

	March 31, 2015	December 31, 2014
Deferred financing costs, net of accumulated amortization of $25,603 and $18,622 at March 31, 2015 and December 31, 2014, respectively	$ 47,381	$ 40,637
Notes receivable	3,926	3,866
Other	5,429	5,578
	$ 56,736	$ 50,081

Deferred financing costs are recorded at cost and amortized over the term of the respective debt agreements (see Note 7). Amortization expense of deferred financing costs was $2.7 million and $1.8 million for the three months ended March 31, 2015 and 2014, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the three months ended March 31, 2015, the Partnership recognized $4.3 million for accelerated amortization of deferred financing costs associated with a reduction of the borrowing base under the revolving credit facility. There was no accelerated amortization of deferred financing costs during the three months ended March 31, 2014.

At March 31, 2015 and December 31, 2014, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership's consolidated balance sheets. The notes have a maturity date of March 31, 2022, and a 2.25% per annum interest rate. The maturity date of the notes can be extended to March 31, 2027, subject to certain conditions, including an extension fee of 1.0% of the outstanding principal balance. For the three months ended March 31, 2015 and 2014, approximately $21,000 and $23,000, respectively, of interest income was recognized within other, net on the Partnership's consolidated statements of operations. At March 31, 2015 and December 31, 2014, the Partnership recorded no allowance for credit losses within its consolidated balance sheets based upon payment history and ongoing credit evaluations associated with the notes receivable.

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

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

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

The Partnership proportionately consolidates its ownership interest of the asset retirement obligations of its Drilling Partnerships. At March 31, 2015, the Drilling Partnerships had $45.1 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 March 31, 2015, the Partnership has withheld $2.1 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 March 31,	
	2015	2014
Asset retirement obligations, beginning of year	$106,528	$89,776
Liabilities incurred	165	529
Liabilities settled	(347)	(217)
Accretion expense	1,553	1,301
Asset retirement obligations, end of period	$107,899	$91,389

21

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

NOTE 7 - DEBT

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

	March 31, 2015	December 31, 2014
Revolving credit facility	$559,000	$696,000
Term loan facility	242,658	—
7.75 % Senior Notes – due 2021	374,563	374,544
9.25 % Senior Notes – due 2021	323,957	323,916
Total debt	1,500,178	1,394,460
Less current maturities	—	—
Total long-term debt	$1,500,178	$1,394,460

Credit Facility

On February 23, 2015, the Partnership entered into a Sixth Amendment to its Second Amended and Restated Credit Agreement dated July 31, 2013 with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the "Credit Agreement"). Among other things, the Sixth Amendment:

- reduces the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;
- permits the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;
- reschedules the Partnership's May 1, 2015 borrowing base redetermination for July 1, 2015;
- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels;
- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and
- revises the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ended on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

The Partnership's borrowing base is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. At March 31, 2015, $559.0 million was outstanding under the credit facility. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.3 million was outstanding at March 31, 2015. The Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by certain of the Partnership's material subsidiaries, and any non-guarantor subsidiaries of the Partnership are minor. Borrowings under the credit facility bear interest, at the Partnership's election, at either an adjusted LIBOR rate plus an applicable margin between 1.50% and 2.75% per annum or the base rate (which is the higher of the bank's prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 0.50% and 1.75% per annum. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At March 31, 2015, the weighted average interest rate on outstanding borrowings under the credit facility was 2.8%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of March 31, 2015. The Credit Agreement also requires the Partnership to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than (i) 5.25 to 1.0 as of the last day of the quarters ended on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. Based on the definitions contained in the Partnership's Credit Agreement, at March 31, 2015, the Partnership's ratio of current assets to current liabilities was 1.6 to 1.0, and its ratio of Total Funded Debt to EBITDA was 4.2 to 1.0.

Term Loan Facility

On February 23, 2015, the Partnership entered into a Second Lien Credit Agreement with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"). The Term Loan Facility matures on February 23, 2020. The Term Loan Facility is presented net of unamortized discount of $7.3 million at March 31, 2015.

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

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;
- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

The Partnership's obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of its assets and those of its restricted subsidiaries (the "Loan Parties") that guarantee the Partnership's existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by the Partnership's material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at the Partnership's option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the applicable maturity date for Eurodollar loans and quarterly for ABR loans. At March 31, 2015, the weighted average interest rate on outstanding borrowings under the term loan facility was 10.0%.

The Second Lien Credit Agreement contains customary covenants that limit the Partnership's ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in the Partnership's existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. The Partnership was in compliance with these covenants as of March 31, 2015.

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

Senior Notes

At March 31, 2015, the Partnership had $374.6 million outstanding of its 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"). The 7.75% Senior Notes were presented net of a $0.4 million unamortized discount as of March 31, 2015. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the Partnership may redeem the 7.75% Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 7.75% Senior Notes.

At March 31, 2015, the Partnership had $324.0 million outstanding of its 9.25% senior unsecured notes due 2021 ("9.25% Senior Notes"). The 9.25% Senior Notes were presented net of a $1.0 million unamortized discount as of March 31, 2015. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time prior to August 15, 2017, the Partnership may redeem the 9.25% Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid interest, if any. At any time on or after August 15, 2017, the Partnership may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of $75.0 million of 9.25% Senior Notes on October 14, 2014, the Partnership entered into a registration rights agreement whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 11, 2015. On April 15, 2015, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was subsequently launched on April 15, 2015.

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

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants, including limitations of the Partnership's ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of the Partnership's assets. The Partnership was in compliance with these covenants as of March 31, 2015.

Total cash payments for interest by the Partnership were $36.7 million and $26.5 million for the three months ended March 31, 2015 and 2014, respectively.

NOTE 8 – DERIVATIVE INSTRUMENTS

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

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

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership's consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership's consolidated balance sheets as the initial value of the options. The Partnership reflected net derivative assets on its consolidated balance sheets of $332.2 million and $269.3 million at March 31, 2015 and December 31, 2014, respectively. Of the $159.3 million of deferred gains in accumulated other comprehensive income on the Partnership's consolidated balance sheet at March 31, 2015, the Partnership will reclassify $81.9 million of gains to its consolidated statement of operations over the next twelve month period as these contracts expire with the remaining gains of $77.4 million being reclassified to the Partnership's consolidated statements of operations in later periods as the remaining contracts expire. During the three months ended March 31, 2014, no amounts were reclassified from other comprehensive income related to derivative instruments entered into during that period.

The following table summarizes the commodity derivative activity for the three months ended March 31, 2015 (in thousands):

	Three Months Ended March 31, 2015		
Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets(1)	$	(26,596	)
Portion of settlements attributable to subsequent mark to market gains		(15,203	)
		(41,799	)

Total cash settlements on commodity derivative contracts		
2015 Unrealized gains prior to settlement[(2)]		3,203
Unrealized gain on open derivative contracts at March 31, 2015, net of amounts recognized in income in prior year[(2)]		101,320
	$	104,523

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

The Partnership had $41.8 million of cash settlements during the three months ended March 31, 2015. As the underlying prices and terms in the Partnership's derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the three months ended March 31, 2015 and 2014 for hedge ineffectiveness.

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

Offsetting Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Assets Presented in the Consolidated Balance Sheets
As of March 31, 2015			
Current portion of derivative assets	$ 145,520	$ (21)	$ 145,499
Long-term portion of derivative assets	186,916	(198)	186,718
Total derivative assets	$ 332,436	$ (219)	$ 332,217
As of December 31, 2014			
Current portion of derivative assets	$ 141,464	$ (98)	$ 141,366
Long-term portion of derivative assets	128,303	(370)	127,933
Total derivative assets	$ 269,767	$ (468)	$ 269,299

Offsetting Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Balance Sheets
As of March 31, 2015			
Current portion of derivative liabilities	$ (21)	$ 21	$ —
Long-term portion of derivative liabilities	(198)	198	—
Total derivative liabilities	$ (219)	$ 219	$ —
As of December 31, 2014			
Current portion of derivative liabilities	$ (98)	$ 98	$ —
Long-term portion of derivative liabilities	(370)	370	—
Total derivative liabilities	$ (468)	$ 468	$ —

The Partnership enters into commodity future option and collar contracts to achieve more predictable cash flows by hedging its exposure to changes in commodity prices. At any point in time, such contracts may include regulated 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 were recorded at their fair values.

At March 31, 2015, the Partnership had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)[1]	Average Fixed Price (per MMBtu)[1]	Fair Value Asset (in thousands)[2]
2015	40,053,400	$ 4.210	$ 56,994
2016	53,546,300	$ 4.229	59,049
2017	49,920,000	$ 4.219	42,447
2018	40,800,000	$ 4.170	28,182
2019	15,960,000	$ 4.017	7,319
			$ 193,991

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)	Fair Value Asset/ (Liability) (in thousands)(2)
2015	Puts purchased	2,520,000	$ 4.210	$ 3,670
2015	Calls sold	2,520,000	$ 5.090	(16)
				$ 3,654

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)
2015	Puts purchased	1,080,000	$ 4.000	$ 1,328
2016	Puts purchased	1,440,000	$ 4.150	1,633
				$ 2,961

Natural Gas – WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset (in thousands)(7)
2015	3,600,000	$ (0.090)	$ 239
			$ 239

Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(8)
2015	3,780,000	$ 1.956	$ 3,122
			$ 3,122

Natural Gas Liquids – Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(4)
2015	6,048,000	$ 1.016	$ 2,896
			$ 2,896

Natural Gas Liquids – Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(5)
2015	1,134,000	$ 1.248	$ 676
			$ 676

Natural Gas Liquids – Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(6)
2015	1,134,000	$ 1.263	$ 689
			$ 689

Natural Gas Liquids – Crude Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Asset (in thousands)(3)
2016	84,000	$ 85.651	$ 2,274
2017	60,000	$ 83.780	1,315
			$ 3,589

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Asset (in thousands)(3)
2015	1,444,500	$87.585	$ 50,453
2016	1,425,000	$83.496	35,544
2017	1,140,000	$77.285	17,766
2018	1,080,000	$76.281	13,804
2019	540,000	$ 68.371	2,196
			$ 119,763

Crude Oil – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)(1)	Average Floor and Cap (per Bbl)(1)	Fair Value Asset/ (Liability) (in thousands)(3)

2015	Puts purchased	19,500	$83.846		$ 638
2015	Calls sold	19,500	$110.654		(1)
					$ 637
				Total net assets	$ 332,217

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

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 March 31, 2015, net unrealized derivative assets of $3.0 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At March 31, 2015, the Partnership had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under its revolving credit facility (see Note 7), the Partnership is required to utilize this secured hedge facility for future commodity risk management activity for its equity production volumes within the participating Drilling Partnerships. Each participating Drilling Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets and by a guarantee of the general partner of the Drilling Partnership. The Partnership, as general partner of the Drilling Partnerships, administers the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

NOTE 9 – FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

Information for assets and liabilities measured at fair value at March 31, 2015 and December 31, 2014 was as follows (in thousands):

As of March 31, 2015	Level 1	Level 2	Level 3	Total
Derivative assets, gross				
Commodity swaps	$ —	$325,167	$ —	$325,167
Commodity puts	—	2,961	—	2,961
Commodity options	—	4,308	—	4,308
Total derivative assets, gross	—	332,436	—	332,436
Derivative liabilities, gross				
Commodity swaps	—	(202)	—	(202)
Commodity options	—	(17)	—	(17)
Total derivative liabilities, gross	—	(219)	—	(219)
Total derivatives, fair value, net	$ —	$332,217	$ —	$332,217

As of December 31, 2014	Level 1	Level 2	Level 3	Total
Derivative assets, gross				
Commodity swaps	$ —	$261,680	$ —	$261,680
Commodity puts	—	2,767	—	2,767
Commodity options	—	5,320	—	5,320
Total derivative assets, gross	—	269,767	—	269,767
Derivative liabilities, gross				
Commodity swaps	—	(401)	—	(401)
Commodity options	—	(67)	—	(67)
Total derivative liabilities, gross	—	(468)	—	(468)
Total derivatives, fair value, net	$ —	$269,299	$ —	$269,299

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 values of the Partnership's long-term debt at March 31, 2015 and December 31, 2014, which consist of its Senior Notes and outstanding borrowings under its revolving credit and term loan facilities (see Note 7), were $1,286.4 million and $1,219.8 million, respectively, compared with the carrying amounts of $1,500.2 million and $1,394.5 million, respectively. At March 31, 2015 and December 31 2014, the carrying values of outstanding borrowings under the Partnership's respective revolving and term loan credit facilities (see Note 7), which bear interest at variable interest rates, approximated their estimated fair values. The estimated fair values of the Partnership's Senior Notes were based upon the market approach and calculated using yields of the Partnership Senior Notes 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 the Partnership's 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 months March 31, 2015 and 2014 were as follows (in thousands):

	Three Months Ended March 31,			
	2015		2014	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$165	$165	$529	$529

Total	$165	$165	$529	$529

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. No impairments were recognized during the three months ended March 31, 2015 and 2014.

During the year ended December 31, 2014, the Partnership completed the Eagle Ford, Rangely and GeoMet acquisitions (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 Eagle Ford and Rangely acquisitions as of the respective acquisition dates, which are reflected in the Partnership's consolidated balance sheet as of March 31, 2015, 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.

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

Relationship with ATLS's Development Subsidiary. The Partnership's general partner, ATLS, also maintains an ownership interest in its Development Subsidiary, a partnership that conducts natural gas and oil operations in the mid-continent region of the United States. On November 5, 2014, the Partnership and the Development Subsidiary completed the Eagle Ford Acquisition (see Note 3).

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. The Partnership has structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, the Partnership is not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and the Partnership may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that it does not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by the Partnership to reflect current well performance, commodity prices and production costs, among other items. Based on its historical experience, as of March 31, 2015, the management of the Partnership believes that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

While its historical structure has varied, the Partnership has generally agreed to subordinate a portion of its share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. The Partnership periodically compares the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, the Partnership recognizes subordination as an estimated reduction of its pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which the Partnership has recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, the Partnership will recognize an estimated increase in its portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized. For the three months ended March 31, 2015 and 2014, $0.5 million and $3.5 million, respectively, of the Partnership's gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses.

In connection with the Eagle Ford Acquisition (see Note 3), the Partnership guaranteed the timely payment of the deferred portion of the purchase price that is to be paid by ATLS's Development Subsidiary. Pursuant to the agreement between the Partnership and ATLS's Development Subsidiary, the Partnership will have the right to receive some or all of the assets acquired by the Development Subsidiary in the event of its failure to contribute its portion of any deferred payments. The Partnership's deferred purchase obligation is included within accrued liabilities on the Partnership's consolidated balance sheets at March 31, 2015 and December 31, 2014.

In connection with the GeoMet 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 March 31, 2015 were as follows: 2015— $2.3 million; 2016—$2.3 million; 2017—$1.9 million; 2018—$1.8 million; 2019—$1.8 million; thereafter — $6.5 million.

In connection with the Partnership's acquisition of assets from EP Energy E&P Company, L.P. on July 31, 2013 (the "EP Energy Acquisition"), the Partnership acquired certain long-term annual firm transportation obligations. Estimated fixed and determinable portions of the Partnership's firm transportation obligations as of March 31, 2015 were as follows: 2015—$6.2 million; 2016—$2.1 million; and 2017 to 2019—none.

As of March 31, 2015, the Partnership is committed to expend approximately $3.8 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

Equity Offerings

In October 2014, in connection with the Eagle Ford Acquisition (see Note 3), the Partnership issued 3,200,000 8.625% Class D Preferred Units at a public offering price of $25.00 per Class D Preferred Unit, yielding net proceeds of approximately $77.3 million from the offering, after deducting underwriting discounts and estimated offering expenses. The Partnership used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition. On March 31, 2015, to partially pay its portion of the quarterly installment related to the Eagle Ford Acquisition, the Partnership issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit. On January 15, 2015, the Partnership paid an initial quarterly distribution of $0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015 (see Note 13). The Partnership will pay future cumulative distributions on a quarterly basis, at an annual rate of $2.15625 per unit, or 8.625% of the liquidation preference.

The Class D Preferred Units rank senior to the Partnership's common units and Class C Preferred Units with respect to the payment of distributions and distributions upon a liquidation event and equal with the Partnership's Class B convertible preferred units. The Class D Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change in control. At any time on or after October 15, 2019, the Partnership may, at its option, redeem the Class D Preferred Units in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership may redeem the Class D Preferred Units following certain changes of control, as described in the Certificate of Designation. If the Partnership does not exercise this redemption option upon a change of control, then holders of the Class D Preferred Units will have the option to convert the Class D Preferred Units into a number of Partnership common units per Class D Preferred Unit as set forth in the Certificate of Designation. If the Partnership exercises any of its redemption rights relating to the Class D Preferred Units, the holders of such Class D Preferred Units will not have the conversion right described above with respect to the Class D Preferred Units called for redemption.

In August 2014, the Partnership entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to the equity distribution agreement, the Partnership may sell from time to time through the Agents common units representing limited partner interests of the Partnership having an aggregate offering price of up to $100.0 million. Sales of common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. The Partnership will pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, the Partnership may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between the Partnership and such Agent. During the three months ended March 31, 2015, the Partnership issued 420,586 common limited partner units under the equity distribution program for net proceeds of $3.3 million, net of $0.1 million in commissions paid.

In May 2014, in connection with 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 $297.3 million.

In March 2014, in connection with the GeoMet Acquisition (see Note 3), 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 $129.0 million.

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 whereby it distributes 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, 2014 through March 31, 2015 were as follows (in thousands, except per unit amounts):

Date Cash Distribution Paid	For 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
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
August 14, 2014	June 30, 2014	$ 0.1966	$ 16,029	$ 1,492		$ 1,377
September 12, 2014	July 31, 2014	$ 0.1966	$ 16,028	$ 1,493		$ 1,378
October 15, 2014	August 31, 2014	$ 0.1966	$ 16,032	$ 1,491		$ 1,378
November 14, 2014	September 30, 2014	$ 0.1966	$ 16,032	$ 1,492		$ 1,378
December 15, 2014	October 31, 2014	$ 0.1966	$ 16,033	$ 1,491		$ 1,378
January 14, 2015	November 30, 2014	$ 0.1966	$ 16,779	$ 745	(1)	$ 1,378
February 13, 2015	December 31, 2014	$ 0.1966	$ 16,782	$ 745	(1)	$ 1,378
March 17, 2015	January 31, 2015	$ 0.1083	$ 9,284	$ 643	(1)	$ 203
April 14, 2015	February 28, 2015	$ 0.1083	$ 9,347	$ 643	(1)	$ 204

(1) Excludes the Class D Preferred Unit quarterly distribution (see Note 12).

At December 31, 2014, the Partnership had 3.2 million of its 8.625% Class D Preferred Units outstanding (see Note 12). On January 15, 2015, the Partnership paid an initial quarterly distribution of $0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015.

At March 31, 2015, the Partnership had an additional 4.0 million of its 8.625% Class D Preferred Units outstanding (see Note 12). On April 15, 2015, the Partnership paid a quarterly distribution of $0.539063 per unit for the first quarter of 2015 to holders of record as of April 1, 2015.

On April 22, 2015, the Partnership declared a monthly distribution of $0.1083 per common unit for the month of March 2015. The $10.3 million distribution, including $0.2 million and $0.6 million to the general partner and preferred limited partners, respectively, will be paid on May 15, 2015 to unitholders of record at the close of business on May 8, 2015.

NOTE 14 — BENEFIT PLAN

2012 Long-Term Incentive Plan

The Partnership's 2012 Long-Term Incentive Plan ("2012 LTIP"), effective March 2012, provides incentive awards to officers, employees and directors and employees of the general partner and its affiliates, consultants and joint venture partners (collectively, the "Participants"), who perform services for the Partnership. The 2012 LTIP is administered by the board of the general partner, a committee of the board or the board (or committee of the board) of an affiliate (the "LTIP Committee"). Under the 2012 LTIP, the LTIP Committee may grant awards of phantom units, restricted units or unit options for an aggregate of 2,900,000 common limited partner units. At March 31, 2015, the Partnership had 2,085,310 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 135,663 phantom units, restricted units and unit options available for grant. Share based payments to non-employee directors, which have a cash settlement option, are recognized within liabilities in the consolidated financial statements based upon their current fair market value.

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 upon vesting. 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 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 March 31, 2015, 194,224 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at March 31, 2015 include DERs. During the three months ended March 31, 2015 and 2014, the Partnership paid $0.4 million and $0.6 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 March 31,			
	2015		2014	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of year	799,192	$ 22.70	839,808	$ 24.31
Granted	—	—	3,500	20.99
Vested and issued(1)	(167,182)	23.97	(15,500)	22.69
Forfeited	—	—	(15,500)	22.63
Outstanding, end of period(2)(3)	632,010	$ 22.37	812,308	$ 24.35
Vested and not yet issued(4)	110,125	$ 24.67	6,875	$ 22.76
Non-cash compensation expense recognized (in thousands)		$ 2,514		$ 1,731

(1) The intrinsic values of phantom unit awards vested during the three months ended March 31, 2015 and 2014 were $1.6 million and $0.3 million, respectively.
(2) The aggregate intrinsic value for phantom unit awards outstanding at March 31, 2015 was $4.9 million.
(3) There were approximately $29,000 and $0.2 million recognized as liabilities on the Partnership's consolidated balance sheets at March 31, 2015 and December 31, 2014, respectively, representing 6,647 and 26,579 units, 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 $21.63 and $21.16 at March 31, 2015 and December 31, 2014, respectively. There was $0.1 million recognized as liabilities on the Partnership's consolidated balance sheet at the period ended March 31, 2014 representing 16,084 units due to the option of the participants to settle in cash instead of units. The weighted average grant date fair value for these units was $22.15 for the period ending March 31, 2014.
(4) The intrinsic values of phantom unit awards vested, but not yet issued, at March 31, 2015 and 2014 were $1.1 million and $0.1 million, respectively.

At March 31, 2015, the Partnership had approximately $4.2 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 1.8 years.

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 106,950 unit options outstanding under the 2012 LTIP at March 31, 2015 that will vest within the following twelve months. No cash was received from the exercise of options for the three months ended March 31, 2015 and 2014.

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

	Three Months Ended March 31,			
	2015		2014	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of year	1,458,300	$ 24.66	1,482,675	$ 24.66
Granted	—	—	—	—
Exercised (1)	—	—	—	—
Forfeited	(5,000)	24.67	(10,000)	23.40
Outstanding, end of period(2)(3)	1,453,300	$ 24.66	1,472,675	$ 24.66
Options exercisable, end of period(4)	1,238,275	$ 24.67	368,825	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 831		$ 612

(1) No options were exercised during the three months ended March 31, 2015 and 2014.
(2) The weighted average remaining contractual life for outstanding options at March 31, 2015 was 7.1 years.
(3) There was no aggregate intrinsic value of options outstanding at March 31, 2015. The aggregate intrinsic value of options outstanding at March 31, 2014 was approximately $2,000.
(4) The weighted average remaining contractual life for exercisable options at March 31, 2015 was 7.1 years. There were no intrinsic values for options exercisable at March 31, 2015 and 2014.

At March 31, 2015, the Partnership had approximately $0.2 million in unrecognized compensation expense related to unvested unit options outstanding under the 2012 LTIP based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 1.0 years. 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.

Restricted Units

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

NOTE 15 – OPERATING SEGMENT INFORMATION

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

	Three Months Ended March 31,	
	2015	2014
Gas and oil production:		
Revenues	$205,495	$96,245
Operating costs and expenses	(44,220)	(36,792)
Depreciation, depletion and amortization expense	(39,012)	(48,029)
Segment income	$122,263	$11,424
Well construction and completion:		
Revenues	$23,655	$49,377
Operating costs and expenses	(20,570)	(42,936)
Segment income	$3,085	$6,441
Other partnership management:(1)		
Revenues	$10,097	$11,723
Operating costs and expenses	(4,615)	(6,895)
Depreciation, depletion and amortization expense	(2,854)	(2,208)
Segment income	$2,628	$2,620
Reconciliation of segment income to net income (loss):		
Segment income:		
Gas and oil production	$122,263	$11,424
Well construction and completion	3,085	6,441
Other partnership management	2,628	2,620
Total segment income	127,976	20,485
General and administrative expenses(2)	(17,131)	(16,455)
Interest expense(2)	(25,197)	(13,187)
Loss on asset sales and disposal(2)	(11)	(1,603)
Net income (loss)	$85,637	$(10,760)
Reconciliation of segment revenues to total revenues:		
Segment revenues:		
Gas and oil production	$205,495	$96,245
Well construction and completion	23,655	49,377
Other partnership management	10,097	11,723
Total revenues	$239,247	$157,345
Capital expenditures:		
Gas and oil production	$32,192	$34,983
Other partnership management	10,094	3,340
Corporate and other	212	1,574
Total capital expenditures	$42,498	$39,897

	March 31, 2015	December 31, 2014
Balance sheet		
Goodwill:		
Gas and oil production	$—	$ —
Well construction and completion	6,389	6,389
Other partnership management	7,250	7,250
	$13,639	$ 13,639
Total assets:		
Gas and oil production	$2,571,524	$ 2,537,296
Well construction and completion	7,145	39,558
Other partnership management	69,745	65,796
Corporate and other	99,162	84,925
	$2,747,576	$ 2,727,575

(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) 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

Issuance of Preferred Units. On April 7, 2015 the Partnership issued 255,000 10.75% Class E Cumulative Redeemable Perpetual Preferred Units (“Class E Preferred Units”) at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. The underwriters have been granted a 30-day option to purchase up to an additional 38,250 Class E Preferred Units at the public offering price less the underwriting discount. The Partnership will pay distributions on the Class E Preferred Units at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

Cash Distributions. On April 22, 2015, the Partnership declared a monthly distribution of $0.1083 per common unit for the month of March 2015. The $10.3 million distribution, including $0.2 million and $0.6 million to the general partner and preferred limited partners, respectively, will be paid on May 15, 2015 to unitholders of record at the close of business on May 8, 2015.

On April 15, 2015, the Partnership paid a quarterly distribution of $0.539063 per Class D Preferred Unit, or $2.2 million, for the first quarter of 2015 to Class D Preferred Unit holders of record as of April 1, 2015.

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, 2014. 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.

On February 27, 2015, our general partner, Atlas Energy Group, LLC ("Atlas Energy Group"; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. ("Atlas Energy"), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as "ATLS"). Atlas Energy Group manages our operations and activities through its ownership of our general partner interest. Concurrent with Atlas Energy Group's unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. ("Targa"; NYSE: TRGP) and ceased trading. At March 31, 2015, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 27.5% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

FINANCIAL PRESENTATION

Our consolidated balance sheets at March 31, 2015 and December 31, 2014, and the consolidated statements of operations for the three months ended March 31, 2015 and 2014 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

Issuance of Preferred Units. On April 7, 2015, we issued 255,000 10.75% Class E Cumulative Redeemable Perpetual Preferred Units at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. The underwriters have been granted a 30-day option to purchase up to an additional 38,250 Class E Preferred Units at the public offering price less the underwriting discount. We will pay distributions on the Class E Preferred Units at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

Cash Distributions. On April 22, 2015, we declared a monthly distribution of $0.1083 per common unit for the month of March 31, 2015. The $10.3 million distribution, including $0.2 million and $0.6 million to the general partner and preferred limited partners, respectively, will be paid on May 15, 2015 to unitholders of record at the close of business on May 8, 2015.

At March 31, 2015, we had 4.0 million of our 8.625% Class D Preferred Units outstanding. On April 15, 2015, we paid a quarterly distribution of $0.539063 per unit, or $2.2 million, for the first quarter of 2015 to holders of record as of April 1, 2015.

RECENT DEVELOPMENTS

Credit Facility Amendment. On February 23, 2015, we entered into a Sixth Amendment to the Second Amended and Restated Credit Agreement (the "Sixth Amendment") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amendment amends the Second Amended and Restated Credit Agreement (the "Credit Agreement"), dated July 31, 2013. Among other things, the Sixth Amendment:

- reduces the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;

- permits the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;

- rescheduled the May 1, 2015 borrowing base redetermination for July 1, 2015;

- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels,

- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and

- revises the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ended on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

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

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries (the "Loan Parties") that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or

(ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the applicable maturity date for Eurodollar loans and quarterly for ABR loans (see "Credit Facilities").

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 pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline Zone 4 (200 Leg), Transco Leidy Line, Columbia Appalachia, NYMEX and Transco Zone 5;
- Mississippi Lime - Southern Star;
- Barnett Shale and Marble Falls- primarily Waha;
- Raton - ANR, Panhandle, and NGPL;
- Black Warrior Basin - Southern Natural;
- Eagle Ford – Transco Zone 1; 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 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 2016. We also hold firm transportation obligations on East Tennessee Natural Gas, Columbia Gas Transmission and Equitrans for the benefit of production from the central Appalachian Basin. The total of firm transportation held is approximately 25,000 dth/d, 15,500 dth/d and 2,300 dth/d, respectively, under contracts expiring between the years 2015 and 2022.

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/pipeline 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. Certain energy activities are conducted by us through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we will recognize a current liability titled “Liabilities Associated with Drilling Contracts” on our consolidated balance sheets. After the Drilling Partnership well is completed and turned in line, we are entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees we are entitled to receive for services provided, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%.

As managing general partner of our Drilling Partnerships, we receive the following Drilling Partnership management fees:

- 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 wells included within the partnership. Such fees are earned, in accordance with the partnership agreement, and recognized as the services are performed, typically between 60 and 270 days, using the percentage of completion method;

- Administration and oversight. For each well drilled by a Drilling Partnership, we receive a fixed fee between $100,000 and $500,000, depending on the type of well drilled, which is earned in accordance with the partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of $75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed; and

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

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

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

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 natural gas, oil and natural gas liquids commodity price markets have suffered significant declines during the fourth quarter of 2014 and the first quarter of 2015. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

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

RESULTS OF OPERATIONS

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various plays throughout the United States. Through March 31, 2015, we have established production positions in the following operating areas:

- the Appalachia Basin assets, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region;
- coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming, where we established a position following our acquisition of certain assets from EP Energy during 2013, as well as the Central Appalachia Basin in West

Virginia and Virginia, where we established a position following our acquisition of assets from GeoMet Inc. in May 2014;

- 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.
- the Rangely field in northwest Colorado, a mature tertiary CO2 flood with low-decline oil production, where we have a 25% non-operated net working interest position following our acquisition on June 30, 2014 ("Rangely Acquisition");
- the Eagle Ford Shale in south Texas, in which we and ATLS's Development Subsidiary acquired acreage and producing wells in November 2014;
- 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 months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
Gross wells drilled:		
Barnett/Marble Falls	3	26
Mississippi Lime	2	3
Total	5	29
Net wells drilled(1):		
Barnett/Marble Falls	2	18
Mississippi Lime	1	1
Total	3	19
Gross wells turned in line:		
Barnett/Marble Falls	14	26
Eagle Ford	2	—
Mississippi Lime	5	5
Total	21	31
Net wells turned in line:		
Barnett/Marble Falls	4	17
Eagle Ford	1	—
Mississippi Lime	2	2
Total	7	19

(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 months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
Production:(1)(2)(3)		
Appalachia:		
Natural gas (MMcf)	2,900	3,703
Oil (000's Bbls)	30	37
Natural gas liquids (000's Bbls)	3	3
Total (MMcfe)	3,099	3,943
Coal-bed Methane:		
Natural gas (MMcf)	11,113	9,753
Oil (000's Bbls)	—	—
Natural gas liquids (000's Bbls)	—	—
Total (MMcfe)	11,113	9,753
Barnett/Marble Falls:		
Natural gas (MMcf)	4,466	5,211
Oil (000's Bbls)	67	75
Natural gas liquids (000's Bbls)	205	231
Total (MMcfe)	6,098	7,049
Rangely/Eagle Ford:		
Natural gas (MMcf)	45	—
Oil (000's Bbls)	352	—
Natural gas liquids (000's Bbls)	32	—
Total (MMcfe)	2,350	—
Mississippi Lime/Hunton:		
Natural gas (MMcf)	682	529
Oil (000's Bbls)	46	27
Natural gas liquids (000's Bbls)	55	44
Total (MMcfe)	1,292	953
Other operating areas:		
Natural gas (MMcf)	296	306
Oil (000's Bbls)	2	2
Natural gas liquids (000's Bbls)	18	30
Total (MMcfe)	420	499
Total production:		
Natural gas (MMcf)	19,502	19,502
Oil (000's Bbls)	498	141
Natural gas liquids (000's Bbls)	314	308
Total (MMcfe)	24,373	22,196
Production per day:(1)(2)(3)		
Appalachia:		
Natural gas (Mcfd)	32,219	41,146
Oil (Bpd)	334	415
Natural gas liquids (Bpd)	35	29

Total (Mcfed)	34,436	43,810
Coal-bed Methane:		
Natural gas (Mcfd)	123,481	108,368
Oil (Bpd)	—	—
Natural gas liquids (Bpd)	—	—
Total (Mcfed)	123,481	108,368
Barnett/Marble Falls:		
Natural gas (Mcfd)	49,617	57,898
Oil (Bpd)	749	834
Natural gas liquids (Bpd)	2,274	2,570

	Three Months Ended March 31,	
	2015	2014
Total (Mcfed)	67,755	78,319
Rangely/Eagle Ford:		
Natural gas (Mcfd)	500	—
Oil (Bpd)	3,911	—
Natural gas liquids (Bpd)	359	—
Total (Mcfed)	26,115	—
Mississippi Lime/Hunton:		
Natural gas (Mcfd)	7,579	5,873
Oil (Bpd)	514	301
Natural gas liquids (Bpd)	615	485
Total (Mcfed)	14,357	10,587
Other operating areas:		
Natural gas (Mcfd)	3,291	3,402
Oil (Bpd)	25	19
Natural gas liquids (Bpd)	204	338
Total (Mcfed)	4,668	5,544
Total production per day:		
Natural gas (Mcfd)	216,687	216,688
Oil (Bpd)	5,533	1,568
Natural gas liquids (Bpd)	3,488	3,422
Total (Mcfed)	270,811	246,628

(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 (excluding the Cedar Bluff area); Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the County Line area of Wyoming; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; 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 and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the three months ended March 31, 2015 and 2014, along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

45

	Three Months Ended March 31,	
	2015	2014
Production revenues (in thousands):(1)		
Appalachia:		
Natural gas revenue	$3,886	$10,462
Oil revenue	2,010	3,044
Natural gas liquids revenue	95	76
Total revenues	$5,991	$13,582
Coal-bed Methane:		
Natural gas revenue	$44,564	$42,582
Oil revenue	—	—
Natural gas liquids revenue	—	—
Total revenues	$44,564	$42,582
Barnett/Marble Falls:		
Natural gas revenue	$11,882	$17,278
Oil revenue	2,357	6,685
Natural gas liquids revenue	3,044	6,648
Total revenues	$17,283	$30,611
Rangely/Eagle Ford:		
Natural gas revenue	$194	$—
Oil revenue	25,980	—
Natural gas liquids revenue	1,098	—
Total revenues	$27,272	$—
Mississippi Lime/Hunton:		
Natural gas revenue	$1,527	$2,525
Oil revenue	1,835	2,427
Natural gas liquids revenue	940	1,941
Total revenues	$4,302	$6,893
Other operating areas:		
Natural gas revenue	$1,211	$1,343
Oil revenue	203	127
Natural gas liquids revenue	146	1,107
Total revenues	$1,560	$2,577
Total production revenues:		
Natural gas revenue	$63,264	$74,190
Oil revenue	32,385	12,283
Natural gas liquids revenue	5,323	9,772
Total revenues	$100,972	$96,245
Average sales price:		
Natural gas (per Mcf):(2)		
Total realized price, after hedge(3) (4)	$3.59	$4.07
Total realized price, before hedge(3)	$2.53	$4.68
Oil (per Bbl):(2)		
Total realized price, after hedge(4)	$80.81	$87.04
Total realized price, before hedge	$43.46	$93.18
Natural gas liquids (per Bbl):(2)		
Total realized price, after hedge(4)	$22.49	$31.73
Total realized price, before hedge	$16.43	$35.65

	Three Months Ended March 31,	
	2015	2014
Production costs (per Mcfe):[(1) (2)]		
Appalachia:		
Lease operating expenses[(5)]	$ 1.12	$ 0.99
Production taxes	0.06	0.06
Transportation and compression	0.33	0.57
	$ 1.52	$ 1.62
Coal-bed Methane:		
Lease operating expenses	$ 1.08	$ 1.01
Production taxes	0.25	0.33
Transportation and compression	0.32	0.33
	$ 1.64	$ 1.68
Barnett/Marble Falls:		
Lease operating expenses	$ 1.41	$ 1.46
Production taxes	0.18	0.32
Transportation and compression	0.07	0.07
	$ 1.66	$ 1.86
Rangely/Eagle Ford:		
Lease operating expenses	$ 3.05	$ —
Production taxes	0.73	—
Transportation and compression	0.02	—
	$ 3.80	$ —
Mississippi Lime/Hunton:		
Lease operating expenses	$ 1.44	$ 1.59
Production taxes	0.07	0.19
Transportation and compression	0.26	0.33
	$ 1.77	$ 2.10
Other operating areas:		
Lease operating expenses	$ 0.71	$ 0.74
Production taxes	0.14	0.18
Transportation and compression	0.22	0.22
	$ 1.08	$ 1.14
Total production costs:		
Lease operating expenses[(5)]	$ 1.37	$ 1.17
Production taxes	0.24	0.27
Transportation and compression	0.22	0.29
	$ 1.84	$ 1.73

(1) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia (excluding the Cedar Bluff area); Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the County Line area of Wyoming; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; 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 months ended March 31, 2015 and 2014. Including the effect of this subordination, the average realized gas sales price was $3.53 per Mcf ($2.48 per Mcf before the effects of financial hedging) and $3.80 per Mcf ($4.42 per Mcf before the effects of financial hedging) for the three months ended March 31, 2015 and 2014, respectively.

(4) Includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015, consisting of $5.6 million associated with natural gas derivative contracts, $7.9 million associated with crude oil derivative contracts, and $1.7 million associated with natural gas liquids derivative contracts for the three months ended March 31, 2015 (see "Item 1. Financial Statements – Note 8").

(5) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for the three months ended March 31, 2015 and 2014. Including the effects of these costs, Appalachia lease operating expenses were $0.95 per Mcfe ($1.35 per Mcfe for total production costs) and $0.57 per Mcfe ($1.20 per Mcfe for total production costs) for the three months ended March 31, 2015 and 2014, respectively. Including the effects of these costs, total lease operating expenses were $1.35 per Mcfe ($1.81 per Mcfe for total production costs) and $1.10 per Mcfe ($1.66 per Mcfe for total production costs) for the three months ended March 31, 2015 and 2014, respectively.

Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014. Total production revenues were $101.0 million for the three months ended March 31, 2015, an increase of $4.8 million from $96.2 million for the three months ended March 31, 2014. This increase principally consisted of a $27.3 million increase attributable to the newly acquired Rangely/Eagle Ford assets, and a $2.0 million increase attributable to the coal-bed methane assets, partially offset by a $13.3 million decrease attributable to the Barnett Shale/Marble Falls operations, a $7.6 million decrease attributable to the Appalachia assets, a $2.6 million decrease attributable to the Mississippi Lime/Hunton assets, and a $1.0 million decrease associated with our other operating areas.

Total production costs were $44.2 million for the three months ended March 31, 2015, an increase of $7.4 million from $36.8 million for the three months ended March 31, 2014. This increase primarily consisted of an $8.9 million increase attributable to the newly acquired Rangely/Eagle Ford assets, a $1.9 million increase attributable to the coal-bed methane assets, a $1.1 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships, and a $0.3 million increase attributable to the Mississippi Lime/Hunton assets, partially offset by a $3.0 million decrease attributable to the Barnett Shale/Marble Falls assets, and a $1.7 million decrease attributable to the Appalachia operations. Total production costs per Mcfe increased to $1.84 per Mcfe for the three months ended March 31, 2015 from $1.73 per Mcfe for the comparable prior year period primarily as a result of the increases in our oil and natural gas liquids production, partially offset by lower operating costs in our legacy regions.

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 months ended March 31, 2015 and 2014. There were no exploratory wells drilled during the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
Drilling partnership investor capital:		
Raised	$ —	$ —
Deployed	$ 23,655	$ 49,377
Gross partnership wells drilled:		
Barnett/Marble Falls	2	23
Mississippi Lime/Hunton	2	3
Total	4	26

Net partnership wells drilled:		
Barnett/Marble Falls	2	11
Mississippi Lime/Hunton	1	3
Total	3	14

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 March 31,	
	2015	2014
Average construction and completion:		
Revenue per well	$ 2,290	$ 3,188
Cost per well	1,991	2,772
Gross profit per well	$ 299	$ 416
Gross profit margin	$ 3,085	$ 6,441
Partnership net wells associated with revenue recognized[1]:		
Appalachia		
Marcellus Shale	—	—
Utica	1	1
Ohio	—	—
Barnett/Marble Falls	5	11
Mississippi Lime/Hunton	4	3
Total	10	15

(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 March 31, 2015 Compared with the Three Months Ended March 31, 2014. Well construction and completion segment margin was $3.1 million for the three months ended March 31, 2015, a decrease of $3.3 million from $6.4 million for the three months ended March 31, 2014. This decrease consisted of a $2.1 million decrease related to fewer wells recognized for revenue within our Drilling Partnerships, and a $1.2 million decrease associated with lower gross profit margin per well. Average revenue and cost per well decreased between periods due primarily to lower capital deployed for Utica Shale wells within the Drilling Partnerships during the three months ended March 31, 2015 compared with 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.

At March 31, 2015, our consolidated balance sheet includes $17.0 million of "liabilities associated with drilling contracts" for funds raised by our Drilling Partnerships that have not been applied to the completion of wells due to the timing of drilling operations, and thus had not been recognized as well construction and completion revenue on our consolidated statements of operations. We expect to recognize this amount as revenue during the remainder of 2015.

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, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales.

Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014. Administration and oversight fee revenues were $1.3 million for the three months ended March 31, 2015, a decrease of $0.4 million from $1.7 million for the three months ended March 31, 2014. This decrease was due to a decrease in the number of wells spud within the current year period compared with the prior year period, particularly within the Marble Falls play.

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 March 31, 2015 Compared with the Three Months Ended March 31, 2014. Well services revenues were $6.6 million for the three months ended March 31, 2015, an increase of $1.1 million from $5.5 million for the three months ended March 31, 2014. Well services expenses were $2.2 million for the three months ended March 31, 2015, a decrease of $0.3 million from $2.5 million for the three months ended March 31, 2014. 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 decrease in well services expense is primarily related to lower 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 March 31, 2015 Compared with the Three Months Ended March 31, 2014. Our net gathering and processing expense for the three months ended March 31, 2015 was net expense of $0.2 million, an unfavorable movement of $0.3 million compared with net income of $0.1 million for the three months ended March 31, 2014. This unfavorable movement was principally due to lower gathering fees from the Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline, in comparison with the prior year period.

Gain on Mark-to-Market Derivatives

On January 1, 2015, we discontinued hedge accounting for our qualified commodity derivatives. As such, subsequent changes in fair value of these derivatives are recognized immediately within gain on mark-to-market derivatives on our combined consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners' capital on our balance sheet, will be reclassified to our combined consolidated statements of operations in the future at the time the originally hedged physical transactions settle.

Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014. We recognized a gain on mark-to-market derivatives of $104.5 million for the three months ended March 31, 2015. This gain was due primarily to mark-to-market gains in the current quarter primarily related to the change in natural gas and oil prices during the period. There were no gains or losses on mark-to-market derivatives during the three months ended March 31, 2014.

Other, net

Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014. Other, net for the three months ended March 31, 2015 was approximately $30,000, compared with approximately $47,000 for the three months ended March 31, 2014.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014. Total general and administrative expenses increased to $17.1 million for the three months ended March 31, 2015 compared with $16.5 million for the three months ended March 31, 2014. This increase was primarily due to a $1.0 million increase in non-cash compensation expense, partially offset by a $0.2 million decrease in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods and a $0.2 million decrease in other corporate activities during the current year period in comparison with the prior year period.

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization decreased to $41.9 million for the three months ended March 31, 2015 compared with $50.2 million for the comparable prior year period, which was primarily due to a $9.0 million decrease in our depletion expense.

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 March 31,	
	2015	2014
Depreciation, depletion and amortization:		
Depletion expense	$39,012	$48,029
Depreciation and amortization expense	2,854	2,208
	$41,866	$50,237
Depletion expense:		
Total	$39,012	$48,029
Depletion expense as a percentage of gas and oil production revenue	39 %	50 %
Depletion per Mcfe	$1.60	$2.16

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 March 31, 2015, depletion expense was $39.0 million, a decrease of $9.0 million compared with $48.0 million for the three months ended March 31, 2014. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 39% for the three months ended March 31, 2015, compared with 50% for the three months ended March 31, 2014. Depletion expense per Mcfe decreased to $1.60 for the three months ended March 31, 2015, compared to $2.16 for the prior year comparable period. Depletion expense and depletion expense per Mcfe decreased between periods principally as a result of the asset impairment recognized at December 31, 2014.

Interest Expense

Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014. Interest expense for the three months ended March 31, 2015 was $25.2 million as compared with $13.2 million for the comparable prior year period. The $12.0 million increase in our interest expense consisted of a $4.3 million accelerated amortization charge related to our reduced credit facility borrowing base, a $3.7 million increase associated with interest expense on our Senior Notes, a $3.0 million increase associated with our Term Loan Facility, a $1.6 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility, and a $0.6 million increase associated with amortization of our deferred financing costs, partially offset by a $1.2 million decrease in interest that was capitalized on our ongoing capital projects. The increase associated with our Senior Notes is primarily due to the issuance of an additional $100.0 million of our 7.75% Senior Notes due 2021 in June 2014 and an additional $75.0 million of our 9.25% Senior Notes due 2021 in October 2014. The increase in interest expense for our Term Loan Facility related to our entry into the Term Loan Facility in February 2015.

Loss on Asset Sales and Disposal

Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014. During the three months ended March 31, 2015 and 2014, we recognized losses on asset sales and disposal of $11,000 and $1.6 million, respectively. The $1.6 million loss on asset sales and disposal for the three months ended March 31, 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.

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 revolving credit facility (see "Credit Facilities"). 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 facilities 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 facilities and other borrowings, the issuance of additional limited partner units, the sale of assets and other transactions.

Cash Flows – Three Months Ended March 31, 2015 Compared with the Three Months Ended March 31, 2014

Net cash used in operating activities of $10.8 million for the three months ended March 31, 2015 represented an unfavorable movement of $33.5 million from net cash provided by operating activities of $22.7 million for the prior year period. The $33.5 million unfavorable movement in net cash used in operating activities resulted from a $21.7 million unfavorable movement in working capital and an $11.8 million unfavorable movement in net income excluding non-cash items. The $21.7 million unfavorable movement in working capital was principally due to a $44.0

million unfavorable movement in accounts payable and accrued liabilities, partially offset by a $22.3 million favorable movement in accounts receivable, prepaid expenses and other. The $44.0 million unfavorable movement in accounts payable and accrued liabilities was primarily due to an unfavorable movement in accounts payable due to the timing of payments and an unfavorable movement in well drilling liabilities between the respective periods. The $22.3 million favorable movement in accounts receivable, prepaid expenses and other was primarily due to the timing of payments received between the comparable periods. The $11.8 million unfavorable movement in net income excluding non-cash items was primarily due to a $104.5 million unfavorable movement in gain on mark-to-market derivatives subsequent to our discontinuation of hedge accounting on January 1, 2015 and an $8.4 million unfavorable movement in depreciation, depletion and amortization, partially offset by a $96.4 million increase in net income.

Net cash used in investing activities of $47.0 million for three months ended March 31, 2015 represented an unfavorable movement of $6.6 million from net cash used in investing activities of $40.4 million for the prior year period. This unfavorable movement was primarily due to a $4.6 million increase in net cash paid for acquisitions and a $2.6 million increase in capital expenditures, partially offset by a $0.6 million favorable movement in other assets. See further discussion of capital expenditures under “Capital Requirements”.

Net cash provided by financing activities of $45.1 million for the three months ended March 31, 2015 represented a favorable movement of $27.2 million from net cash provided by financing activities of $17.9 million for the prior year period. This movement was principally due to a $241.5 million increase in borrowings under our revolving credit and term loan facilities and a $7.1 million decrease in cash distributions paid to limited partners, partially offset by a $125.7 million decrease in net proceeds from the issuance of our common limited partner units, an $83.0 million increase in repayments under our revolving credit facility and a $12.7 million unfavorable movement in deferred financing costs, distribution equivalent rights and other. 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.

The issuance of our Class D Preferred Units as partial payment for the Eagle Ford Acquisition represented a non-cash transaction during the three months ended March 31, 2015.

Capital Requirements

The capital requirements of our natural gas and oil production 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 March 31,	
	2015	2014
Maintenance capital expenditures	$ 15,427	$ 10,800
Expansion capital expenditures	27,071	29,097
Total	$ 42,498	$ 39,897

During the three months ended March 31, 2015, our $42.5 million of total capital expenditures consisted primarily of $12.3 million for wells drilled exclusively for our own account compared with $17.0 million for the comparable prior year period, $13.6 million of investments in our Drilling Partnerships compared with $11.3 million for the prior year comparable period, $2.4 million of leasehold acquisition costs compared with $4.0 million for the prior year comparable period and $14.2 million of corporate and other costs compared with $7.6 million for the prior year comparable period, which primarily related to a decrease in gathering and processing costs.

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 March 31, 2015, we are committed to expend approximately $3.8 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 March 31, 2015, our off-balance sheet arrangements were limited to our letters of credit outstanding of $4.3 million and commitments to spend $3.8 million related to our drilling and completion and capital expenditures, excluding acquisitions.

We are the managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of March 31, 2015, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

In connection with the Eagle Ford Acquisition, we guaranteed the timely payment of the deferred portion of the purchase price that is to be paid by the Development Subsidiary. Pursuant to the agreement between us and the Development Subsidiary, we will have the right to receive some or all of the assets acquired by the Development Subsidiary in the event of its failure to contribute its portion of any deferred payments. In connection with the second installment payments, we and the Development Subsidiary amended the purchase and sale agreement to alter the timing and amount of the quarterly installment payments beginning on March 31, 2015 and ending December 31, 2015.

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, the general partner's board of directors approved a modification to our cash distribution payment practice to a monthly cash distribution program. 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 and D 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 and with respect to our Class D preferred unit, an amount equal to its fixed quarterly distribution; 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 FACILITIES

Revolving Credit Facility

On February 23, 2015, we entered into a Sixth Amendment to its Second Amended and Restated Credit Agreement dated July 31, 2013 with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the "ARP Credit Agreement"). Among other things, the Sixth Amendment:

· reduces the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;

· permits the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;

· rescheduled the March 31, 2015 borrowing base redetermination for July 1, 2015;

· if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increases the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels,

· following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and

· revises the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ended on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

Our borrowing base is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. At March 31, 2015, $559.0 million was outstanding under the credit facility. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.3 million was outstanding at March 31, 2015. Our 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 our material subsidiaries, and any non-guarantor subsidiaries of ours are minor. Borrowings under the credit facility bear interest, at 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% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on our combined 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 its assets. We were in compliance with these covenants as of March 31, 2015. The Credit Agreement also requires the Company to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than (i) 5.25 to 1.0 as of the last day of the quarters ended on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

Term Loan Facility

On February 23, 2015, we entered into a Second Lien Credit Agreement with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the “Term Loan Facility”), and is presented net of $7.3 million of unamortized discount at March 31, 2015. The Term Loan Facility matures on February 23, 2020.

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

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

- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;

- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and

- no premium for prepayments made following 36 months after the closing date.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries (the “Loan Parties”) that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an “ABR Loan”). Interest is generally payable at the applicable maturity date for Eurodollar loans and quarterly for ABR loans.

The Second Lien Credit Agreement contains customary covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in our existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. We were in compliance with these covenants as of March 31, 2015.

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

SENIOR NOTES

At March 31, 2015, we had $374.6 million outstanding of our 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"). The 7.75% Senior Notes were presented net of a $0.4 million unamortized discount as of March 31, 2015. We issued $275.0 million of our 7.75% Senior Notes in a private placement transaction at par on January 23, 2013. Interest is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, we may redeem the 7.75% Senior Notes for up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid interest. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, we must offer to repurchase the 7.75% Senior Notes.

At March 31, 2015, we had $324.0 million outstanding of its 9.25% senior unsecured notes due 2021 ("9.25% Senior Notes"). The 9.25% Senior Notes were presented net of a $1.0 million unamortized discount as of March 31, 2015. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time prior to August 15, 2017, we may redeem the 9.25% ARP Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid interest, if any. At any time on or after August 15, 2017, 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 its 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 its 9.25% Senior Notes at the redemption price of 100.0%. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, we must offer to repurchase its 9.25% ARP Senior Notes.

In connection with the issuance of the $75.0 million of 9.25% Senior Notes on October 14, 2014, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 11, 2015. On April 6, 2015, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was subsequently launched on April 15, 2014.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several, 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 7.75% Senior Notes and 9.25% 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 March 31, 2015.

SECURED HEDGE FACILITY

At March 31, 2015, 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 October 2014, in connection with the Eagle Ford Acquisition, we issued 3,200,000 Class D Preferred Units at a public offering price of $25.00 Class D Preferred Units, yielding net proceeds of approximately $77.3 million from the offering, after deducting underwriting discounts and estimated offering expenses. We used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition. On March 31, 2015, to partially pay our portion of the quarterly installment related to the Eagle Ford Acquisition, we issued an additional 800,000 Class D Preferred Units directly to the seller at a value of $25.00 per unit. On January 15, 2015, we paid an initial quarterly distribution of $0.616927 per Class D Preferred Unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015. We will pay future cumulative distributions on a quarterly basis, at an annual rate of $2.15625 per unit, or 8.625% of the liquidation preference.

The Class D Preferred Units rank senior to our common units and Class C convertible preferred units with respect to the payment of distributions and distributions upon a liquidation event and equal with our Class B convertible preferred units. The Class D Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by us or converted into its common units in connection with a change in control. At any time on or after October 15, 2019, we may, at our option, redeem the Class D Preferred

Units in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we may redeem the Class D Preferred Units following certain changes of control, as described in the Certificate of Designation. If we do not exercise this redemption option upon a change of control, then holders of the Class D Preferred Units will have the option to convert the Class D Preferred Units into a number of our common units per Class D Preferred Unit as set forth in the Certificate of Designation. If we exercise any of our redemption rights relating to the Class D Preferred Units, the holders of such Class D Preferred Units will not have the conversion right described above with respect to the Class D Preferred Units called for redemption.

In August 2014, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the Agents. Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to $100.0 million. Sales of common units, if any, may be made in negotiated transactions or transactions that are deemed to be “at-the-market” offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent. During the three months ended March 31, 2015, we issued 420,586 common limited partner units under the equity distribution program for net proceeds of $3.3 million, net of $0.1 in commissions paid.

In May 2014, in connection with 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 $297.3 million.

In March 2014, in connection with the GeoMet Acquisition, 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 $129.0 million.

ENVIRONMENTAL MATTERS AND REGULATION

On March 26, 2015, the Department of the Interior’s Bureau of Land Management, which we refer to as the BLM, issued a final rule updating the regulations governing hydraulic fracturing on federal and Indian lands. Among the many new requirements, the final rule requires operators planning to conduct hydraulic fracturing to design and implement a casing and cementing program that follows best practices and meets performance standards to protect and isolate usable water, as well as requires operators to monitor cementing operations during well completion. Additionally, the final rule requires that companies publicly disclose the chemicals used in the hydraulic fracturing process, subject to limited exceptions for trade secret materials, using FracFocus; comply with safety standards for storage of produced water in rigid enclosed, covered, or netted and screened above-ground tanks, with very limited exceptions allowing use of pits that must be approved by BLM on a case-by-case basis; and submit detailed information to the BLM on proposed operations, including but not limited to well geology, location of faults and fractures, estimated volume of fluid to be used, and estimated direction and length of fractures. The final rule also provides that where specific state or tribal regulations are equally or more protective than the BLM's new rules, the state or tribe may obtain a variance for that specific regulation. The final rule will be effective on June 24, 2015.

We summarize our environmental matters and regulation within "Item 1: Business" and "Item 1: Risk Factors" on our annual report on Form 10-K for the year ended December 31, 2014.

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, 2014, 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" within this section, recent increases in natural gas and oil drilling have driven an increase in the supply of natural gas and oil and put a downward pressure on domestic prices. Further declines in commodity 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 months ended March 31, 2015 and 2014. During the year ended December 31, 2014, we recognized $555.7 million of asset impairments related to oil and gas properties within our Appalachian and mid-continent operations, which was reduced by $82.3 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairments for the year ended December 31, 2014 principally resulted from the decline in forward commodity prices during the fourth quarter of 2014. These impairments related to the carrying amounts of these gas and oil properties being in excess of our estimate of their fair values at December 31, 2014 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 commodity 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, 2014.

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 months ended March 31, 2015 and 2014.

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 year ended December 31, 2014, we completed the Eagle Ford, Rangely and GeoMet acquisitions. 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 prices, 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, 2014, we engaged independent third-party reserve engineers to prepare reports 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 estimate the cost of future dismantlement, restoration, reclamation and abandonment of our operating assets.

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 interest rate cap 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 March 31, 2015. 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 March 31, 2015, $559.0 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 March 31, 2016 by $5.6 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 March 31, 2016 of approximately $10.2 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 March 31, 2015, 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)]
2015	40,053,400	$ 4.210
2016	53,546,300	$ 4.229
2017	49,920,000	$ 4.219
2018	40,800,000	$ 4.170
2019	15,960,000	$ 4.017

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)[(1)]	Average Floor and Cap (per MMBtu)[(1)]

2015	Puts purchased	2,520,000	$ 4.210
2015	Calls sold	2,520,000	$ 5.090

Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)[(1)]	Average Fixed Price (per MMBtu)[(1)]
2015	Puts purchased	1,080,000	$ 4.000
2016	Puts purchased	1,440,000	$ 4.150

Natural Gas – WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)[1]	Average Fixed Price (per MMBtu)[1]
2015	3,600,000	$ (0.090)

Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

&#1