

ATLAS PIPELINE PARTNERS LP
Form 10-Q
May 08, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2014

OR

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

For the transition period from _____ to _____

Commission file number: 1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE (State or other jurisdiction of incorporation or organization)	23-3011077 (I.R.S. Employer Identification No.)
Park Place Corporate Center One 1000 Commerce Drive, 4th Floor Pittsburgh, Pennsylvania (Address of principal executive office)	15275-1011 (Zip code)
Registrant's telephone number, including area code : (877) 950-7473	

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

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

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

Large accelerated filer <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-accelerated filer <input type="checkbox"/> (Do not check if a smaller reporting company)	Smaller reporting company <input type="checkbox"/>

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

The number of common units of the registrant outstanding on May 5, 2014 was 80,641,731.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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Glossary of Terms

Definitions of terms and acronyms generally used in the energy industry and in this report are as follows:

BPD	Barrels per day. Barrel - measurement for a standard US barrel is 42 gallons. Crude oil and condensate are generally reported in barrels.
BTU	British thermal unit, a basic measure of heat energy
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
EBITDA	Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is a non-GAAP measure.
FASB	Financial Accounting Standards Board
Fractionation	The process used to separate an NGL stream into its individual components.
GAAP	Generally Accepted Accounting Principles
G.P.	General Partner or General Partnership
Keep-Whole	A contract with a natural gas producer whereby the plant operator pays for or returns gas having an equivalent BTU content to the gas received at the well-head.
L.P.	Limited Partner or Limited Partnership
MCF	Thousand cubic feet
MCFD	Thousand cubic feet per day
MMBTU	Million British thermal units
MMCFD	Million cubic feet per day
NGL(s)	Natural Gas Liquid(s), primarily ethane, propane, normal butane, isobutane and natural gasoline
Percentage of Proceeds (POP)	A contract with a natural gas producer whereby the plant operator retains a negotiated percentage of the sale proceeds.
Residue gas	The portion of natural gas remaining after natural gas is processed for removal of NGLs and impurities.

Table of Contents**PART I. FINANCIAL INFORMATION****ITEM 1. FINANCIAL STATEMENTS****ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED BALANCE SHEETS****(in thousands)****(Unaudited)**

	March 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 9,756	\$ 4,914
Accounts receivable	244,711	219,297
Current portion of derivative assets		174
Prepaid expenses and other	24,376	17,393
Total current assets	278,843	241,778
Property, plant and equipment, net	2,825,313	2,724,192
Goodwill	370,396	368,572
Intangible assets, net	654,784	696,271
Equity method investment in joint ventures	269,058	248,301
Long-term portion of derivative assets	3,209	2,270
Other assets, net	45,355	46,461
Total assets	\$ 4,446,958	\$ 4,327,845
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	\$ 394	\$ 524
Accounts payable affiliates	7,089	2,912
Accounts payable	88,331	79,051
Accrued liabilities	42,459	47,449
Accrued interest payable	13,803	26,737
Current portion of derivative liabilities	13,787	11,244
Accrued producer liabilities	191,066	152,309
Total current liabilities	356,929	320,226
Long-term portion of derivative liabilities		320
Long-term debt, less current portion	1,704,549	1,706,786
Deferred income taxes, net	32,892	33,290
Other long-term liabilities	7,177	7,318

Commitments and contingencies**Equity:**

Class D convertible preferred limited partners' interests	471,846	450,749
Class E preferred limited partners' interests	122,793	
Common limited partners' interests	1,637,907	1,703,778
General Partner's interest	44,551	46,118
Total partners' capital	2,277,097	2,200,645
Non-controlling interest	68,314	59,260
Total equity	2,345,411	2,259,905
Total liabilities and equity	\$ 4,446,958	\$ 4,327,845

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31,	
	2014	2013
Revenue:		
Natural gas and liquids sales	\$ 663,130	\$ 383,848
Transportation, processing and other fees third parties	43,382	32,654
Transportation, processing and other fees affiliates	55	71
Derivative loss, net	(8,671)	(12,083)
Other income, net	2,108	3,422
Total revenues	700,004	407,912
Costs and expenses:		
Natural gas and liquids cost of sales	575,468	325,540
Plant operating	24,570	21,271
Transportation and compression	558	588
General and administrative	16,690	12,548
Compensation reimbursement affiliates	1,250	1,250
Other costs	37	530
Depreciation and amortization	49,239	30,458
Interest	23,663	18,686
Total costs and expenses	691,475	410,871
Equity income (loss) in joint ventures	(1,878)	2,040
Loss on early extinguishment of debt		(26,582)
Income (loss) before tax	6,651	(27,501)
Income tax benefit	(398)	(9)
Net income (loss)	7,049	(27,492)
Income attributable to non-controlling interests	(2,462)	(1,369)
Preferred unit imputed dividend effect	(11,378)	
Preferred unit dividends in kind	(9,719)	
Preferred unit dividends	(406)	
Net loss attributable to common limited partners and the General Partner	\$ (16,916)	\$ (28,861)

Allocation of net income (loss) attributable to:

Common limited partner interest	\$ (21,444)	\$ (31,206)
General Partner interest	4,528	2,345
	\$ (16,916)	\$ (28,861)

Net loss attributable to common limited partners per unit:

Basic	\$ (0.27)	\$ (0.48)
Weighted average common limited partner units (basic)	80,595	64,646
Diluted	\$ (0.27)	\$ (0.48)
Weighted average common limited partner units (diluted)	80,595	64,646

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(in thousands, except unit data)

(Unaudited)

	Class D Preferred Limited Partner Units	Class E Preferred Limited Partner Units	Common Limited Partner Units	Class D Preferred Limited Partners	Class E Preferred Limited Partners	Common Limited Partners	General Partner	Non- controlling Interest	Total
Balance at December 31, 2013	13,823,869		80,585,148	\$ 450,749	\$	\$ 1,703,778	\$ 46,118	\$ 59,260	\$ 2,259,905
Issuance of units		5,060,000			122,387				122,387
Issuance of common units under incentive plans			12,833			87			87
Unissued common units under incentive plans						6,345			6,345
Distributions paid in kind units	274,785								
Distributions paid						(50,859)	(6,095)		(56,954)
Contributions from non-controlling interests								6,840	6,840
Distributions to non-controlling interests								(248)	(248)
Net income (loss)				21,097	406	(21,444)	4,528	2,462	7,049
Balance at March 31, 2014	14,098,654	5,060,000	80,597,981	\$ 471,846	\$ 122,793	\$ 1,637,907	\$ 44,551	\$ 68,314	\$ 2,345,411

See accompanying notes to consolidated financial statements

Table of Contents**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(in thousands)****(Unaudited)**

	Three Months Ended March 31,	
	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	\$ 7,049	\$ (27,492)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	49,239	30,458
Equity (income) loss in joint ventures	1,878	(2,040)
Distributions received from equity method joint ventures	2,000	1,800
Non-cash compensation expense	6,439	4,384
Amortization of deferred finance costs	1,856	1,544
Loss on early extinguishment of debt		26,582
Income tax benefit	(398)	(9)
Change in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	(32,317)	(7,211)
Accounts payable and accrued liabilities	24,787	1,608
Accounts payable and accounts receivable affiliates	4,177	(1,162)
Derivative accounts payable and receivable	1,458	12,794
Net cash provided by operating activities	\$ 66,168	\$ 41,256
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(128,331)	(108,516)
Capital contributions to joint ventures	(1,903)	
Other	(450)	126
Net cash used in investing activities	\$ (130,684)	\$ (108,390)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	\$ 322,500	\$ 278,000
Repayments under credit facility	(324,500)	(416,500)
Net proceeds from issuance of long term debt		637,090
Repayment of long-term debt		(365,822)
Payment of premium on retirement of debt		(25,562)
Payment of deferred financing costs	(300)	(99)
Payment for acquisition-based contingent consideration		(6,000)
Principal payments on capital lease	(198)	(2,135)
Net proceeds from issuance of common and preferred limited partner units	122,387	14,144

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General Partner capital contributions		302
Contributions from non-controlling interest holders	6,840	26
Distributions to non-controlling interest holders	(248)	
Distributions paid to common limited partners and the General Partner	(56,954)	(41,170)
Other	(169)	(277)
Net cash provided by financing activities	69,358	71,997
Net change in cash and cash equivalents	4,842	4,863
Cash and cash equivalents, beginning of period	4,914	3,398
Cash and cash equivalents, end of period	\$ 9,756	\$ 8,261

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

March 31, 2014

(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States; natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and the transportation of NGLs in the southwestern region of the United States. The Partnership's operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a majority-owned subsidiary of the Partnership. At March 31, 2014, Atlas Pipeline Partners GP, LLC (the General Partner) owned a combined 2.0% general partner interest in the consolidated operations of the Partnership, through which it manages and effectively controls both the Partnership and the Operating Partnership. The General Partner is a wholly-owned subsidiary of Atlas Energy, L.P. (ATLS), a publicly-traded limited partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. At March 31, 2014, the Partnership had 80,597,981 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS; 14,098,654 Class D convertible preferred units (Class D Preferred Units) outstanding (see Note 5) and 5,060,000 8.25% Class E cumulative redeemable perpetual preferred units (Class E Preferred Units) outstanding (see Note 5).

The accompanying consolidated financial statements, which are unaudited, except the balance sheet dated December 31, 2013 which 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 for interim reporting. The accompanying consolidated financial statements and notes thereto do not include all disclosures normally made in financial statements contained in Form 10-K. In management's opinion, all adjustments necessary for a fair presentation of the Partnership's financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2013. Certain amounts in the prior year's consolidated financial statements have been reclassified to conform to the current year presentation. The results of operations for the three month period ended March 31, 2014 may not necessarily be indicative of the results of operations for the full year ending December 31, 2014.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership's significant accounting policies is included in its audited consolidated financial statements and notes thereto in its Annual Report on Form 10-K for the year ended December 31, 2013.

Principles of Consolidation and Non-Controlling Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership, a variable interest entity of which the Partnership is the primary beneficiary, and the Operating Partnership's wholly-owned and

majority-owned subsidiaries. The General Partner's interest in the Operating Partnership is reported as part of its overall 2.0% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

Table of Contents*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 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). The Partnership does not have any type of transaction, which would be included within other comprehensive income (loss), thus comprehensive income (loss) is equal to net income (loss).

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 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, and net income (loss) attributable to the General Partner's and the preferred unitholders' interests. The General Partner's interest in net income (loss) is calculated on a quarterly basis based upon its 2.0% general partner interest and incentive distributions to be distributed for the quarter (see Note 5), with a priority allocation of net income to the General Partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner's and limited partners' ownership interests.

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

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership's phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 16), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights 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. Therefore, the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the phantom units on a pro-rata basis.

Class D Preferred Units participate in distributions with the common limited partner units according to a predetermined formula (see Note 5), thus they are considered participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution. However, the contractual terms of the Class D Preferred Units do not require the holders to share in the

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losses of the entity, therefore the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the Class D Preferred Units on a pro-rata basis.

Class E Preferred Units do not participate in distributions with the common limited partner units according to a predetermined formula, but rather receive distributions based upon a set percentage rate (see Note 5), thus they are not considered participating securities. However, income available to common limited partners is reduced by the distributions accumulated for the period on the Class E Preferred Units, whether declared or not since the distributions on Class E Preferred Units are cumulative.

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

	Three Months Ended March 31,	
	2014	2013
Net income (loss)	\$ 7,049	\$ (27,492)
Income attributable to non-controlling interests	(2,462)	(1,369)
Preferred unit imputed dividend effect	(11,378)	
Preferred unit dividends in kind	(9,719)	
Preferred unit dividends	(406)	
 Net loss attributable to common limited partners and the General Partner	 (16,916)	 (28,861)
General Partner's cash incentive distributions	4,968	2,986
General Partner's ownership interest	(440)	(641)
 Net income attributable to the General Partner's ownership interests	 4,528	 2,345
 Net loss attributable to common limited partners	 (21,444)	 (31,206)
Net income attributable to participating securities – phantom units ⁽¹⁾		
Net income attributable to participating securities – Class D Preferred Units ⁽²⁾		
 Net loss utilized in the calculation of net loss from continuing operations attributable to common limited partners per unit	 \$ (21,444)	 \$ (31,206)

- (1) Net loss attributable to common limited partners' ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended March 31, 2014 and 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 1,543,000

weighted average phantom units and 1,055,000 weighted average phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

- (2) Net loss attributable to common limited partners' ownership interest is allocated to the Class D Preferred Units on a pro-rata basis (weighted average Class D Preferred Units outstanding as a percentage of the sum of the weighted average Class D Preferred 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 13,964,000 weighted average Class D Preferred Units because the contractual terms of the Class D Preferred 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, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities and the effects of outstanding convertible securities. The phantom units and Class D Preferred Units are participating securities included in the calculation of diluted net income (loss) attributable to common units, due to their participation rights and due to their dilution if converted. The Class E Preferred Units are not participating securities and are not convertible and thus are not included in the units outstanding for calculation of diluted net income (loss) attributable to common limited partners per unit.

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

	Three Months Ended	
	March 31,	
	2014	2013
Weighted average number of common limited partner units basic	80,595	64,646
Add effect of dilutive securities – phantom units ⁽¹⁾		
Add effect of convertible preferred limited partner units ⁽²⁾		
Weighted average common limited partner units – diluted	80,595	64,646

- (1) For the three months ended March 31, 2014 and 2013, approximately 1,543,000 weighted average phantom units and 1,055,000 weighted average phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.
- (2) For the three months ended March 31, 2014, approximately 13,964,000 weighted average Class D Preferred Units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive.

Revenue Recognition

The Partnership accrues unbilled revenue and the related purchase costs due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership's records and management estimates of the related gathering and compression fees, which are, in turn, based upon applicable product prices. The Partnership had unbilled revenues at March 31, 2014 and December 31, 2013 of \$182.4 million and \$134.9 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments. Checks outstanding at the end of a period that exceed available cash balances held at the bank are considered to be book overdrafts and are reclassified to accounts payable. At March 31, 2014 and December 31, 2013, the Partnership reclassified the balances related to book overdrafts of \$17.6 million and \$28.8 million, respectively, from cash and cash equivalents to accounts payable on the Partnership's consolidated balance sheets.

Recently Adopted Accounting Standards

In July 2013, the FASB issued Accounting Standard Update (ASU) 2013-11, Income Taxes (Topic 740) Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result

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from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership applied these requirements upon the adoption of the ASU on January 1, 2014. The adoption had no material impact on the Partnership's financial position or results of operations.

NOTE 3 ACQUISITIONS

On May 7, 2013, the Partnership completed the acquisition of 100% of the equity interests of TEAK Midstream, LLC (TEAK) for \$974.7 million in cash, including final purchase price adjustments, less cash received (the TEAK Acquisition). The assets of these companies include gas gathering, and processing facilities in Texas. The acquisition includes a 75% interest in T2 LaSalle Gathering Company L.L.C. (T2 LaSalle); a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (T2 Eagle Ford); and a 50% interest in T2 EF Cogeneration Holdings L.L.C. (T2 Co-Gen and together with T2 Eagle Ford and T2 LaSalle (the T2 Joint Ventures).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their acquisition date fair values. The accounting for the business combination is based on preliminary data that remains subject to adjustment and could change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

Cash	\$ 8,074
Accounts receivable	11,055
Prepaid expenses and other	1,626
Property, plant and equipment	193,877
Intangible assets	430,000
Goodwill	190,683
Equity method investment in joint ventures	183,801
 Total assets acquired	 1,019,116
Accounts payable and accrued liabilities	(35,296)
Other long term liabilities	(1,075)
 Total liabilities acquired	 (36,371)
 Net assets acquired	 982,745
Less cash received	(8,074)
 Net cash paid for acquisition	 \$ 974,671

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Two indirect subsidiaries of the Partnership hold a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (NYSE: CVX), which owns the remaining 80% interest. The Partnership accounts for its subsidiaries' ownership interest in WTLPG under the equity method of accounting, with recognition of income of WTLPG as equity income in joint ventures on its consolidated statements of operations.

On May 5, 2014, the Partnership announced that it had entered into a definitive agreement to sell its subsidiaries holding interests in WTLPG to a subsidiary of Martin Midstream Partners L.P. for \$135.0 million in cash, subject to certain closing adjustments. The proceeds will be used to pay down the revolving credit facility.

T2 Joint Ventures

On May 7, 2013, the Partnership acquired a 75% interest in T2 LaSalle, a 50% interest in T2 Eagle Ford and a 50% interest in T2 EF Co-Gen as part of the TEAK Acquisition (see Note 3). The T2 Joint Ventures are operated by TexStar Midstream Services, L.P. (TexStar), the investor owning the remaining interests. The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The Partnership accounts for its investments in the joint ventures under the equity method of accounting.

The Partnership evaluated whether the T2 Joint Ventures should be subject to consolidation. The T2 Joint Ventures do meet the qualifications of a Variable Interest Entity (VIE), but the Partnership does not meet the qualifications as the primary beneficiary. Even though the Partnership owns a 50% or greater interest in the T2 Joint Ventures, the Partnership does not have controlling financial interests in these entities. Since the Partnership shares equal management rights with TexStar, and TexStar is the operator of the T2 Joint Ventures, the Partnership determined that it is not the primary beneficiary of the VIEs and should not consolidate the T2 Joint Ventures. The Partnership accounts for its investment in the T2 Joint Ventures under the equity method, since the Partnership does not have a controlling financial interest, but does have a significant influence. The Partnership's maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment; any additional capital contribution commitments and the Partnership's share of any approved operating expenses incurred by the VIEs.

The following table presents the value of the Partnership's equity method investments in joint ventures as of March 31, 2014 and December 31, 2013 (in thousands):

	March 31, 2014	December 31, 2013
WTLPG	\$ 85,517	\$ 85,790
T2 LaSalle	58,731	50,534
T2 Eagle Ford	110,091	97,437
T2 EF Co-Gen	14,719	14,540
Equity method investment in joint ventures	\$ 269,058	\$ 248,301

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The valuation assessment for the TEAK Acquisition has not been completed as of March 31, 2014 and the estimates of fair value of equity method investments reflected as of March 31, 2014 are subject to change (see Note 3).

The following table presents the Partnership's equity income (loss) in joint ventures for the three months ended March 31, 2014 and 2013 (in thousands):

	Three Months Ended March 31,	
	2014	2013
WTLPG	\$ 1,727	\$ 2,040
T2 LaSalle	(1,113)	
T2 Eagle Ford	(2,045)	
T2 EF Co-Gen	(447)	
Equity income (loss) in joint ventures	\$ (1,878)	\$ 2,040

NOTE 5 EQUITY**Common Units**

The Partnership had an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, the Partnership offered and sold through Citigroup, as its sales agent, common units for \$150.0 million. Sales were at market prices prevailing at the time of the sale. During the three months ended March 31, 2013, the Partnership issued 447,785 common units under the equity distribution program for net proceeds of \$14.1 million, net of \$0.3 million in commission paid to Citigroup. The Partnership also received a capital contribution from the General Partner of \$0.3 million to maintain its 2.0% general partner interest in the Partnership. The net proceeds from the common unit offering were utilized for general partnership purposes. As of December 31, 2013, the Partnership had used the full capacity under the equity distribution program.

Cash Distributions

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders (subject to the rights of any other class or series of the Partnership's securities with the right to share in the Partnership's cash distributions) and to the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels, including the General Partner's 2.0% interest. The General Partner, which holds all the incentive distribution rights in the Partnership, has agreed to allocate up to \$3.75 million of its incentive distribution rights per quarter back to the Partnership after the General Partner receives the initial \$7.0 million per quarter of incentive distribution rights.

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Common unit and General Partner distributions declared by the Partnership for quarters ending from March 31, 2013 through December 31, 2013 were as follows:

For Quarter Ended	Date Cash Distribution Paid	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
March 31, 2013	May 15, 2013	0.59	45,382	3,980
June 30, 2013	August 14, 2013	0.62	48,165	5,875
September 30, 2013	November 14, 2013	0.62	49,298	6,013
December 31, 2013	February 14, 2014	0.62	49,969	6,095

On April 22, 2014, the Partnership declared a cash distribution of \$0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2014. The \$56.1 million distribution, including \$6.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on May 15, 2014 to unitholders of record at the close of business on May 8, 2014.

Class D Preferred Units

The Partnership's Class D Preferred Units are presented combined with a net \$50.2 million unaccreted beneficial conversion discount on the Partnership's consolidated balance sheets as of March 31, 2014. For the three months ended March 31, 2014, the Partnership recorded \$11.4 million within preferred unit imputed dividend effect on the Partnership's consolidated statements of operations to recognize the accretion of the beneficial conversion discount.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance in May 2013, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of the General Partner. For the three months ended March 31, 2014, the Partnership recorded Class D Preferred Unit distributions in kind of \$9.7 million as preferred dividends in kind on the Partnership's consolidated statements of operations and distributed 274,785 Class D Preferred Units to the holders of the Class D Preferred Units. The Partnership considers preferred unit distributions paid in kind to be a non-cash financing activity.

On April 22, 2014, the Partnership declared a cash distribution of \$0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2014. Based on this declaration, the Partnership will issue approximately 317,000 Class D Preferred Units as a preferred unit distribution in kind for the quarter ended March 31, 2014 on May 15, 2014, to the preferred unitholders of record at the close of business on May 8, 2014.

Class E Preferred Units

On March 17, 2014, the Partnership issued 5,060,000 of its Class E Preferred Units to the public at an offering price of \$25.00 per Class E Preferred Unit. The Partnership received \$122.4 million in net proceeds. The proceeds were used to pay down the revolving credit facility.

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The Partnership will make cumulative cash distributions on the Class E Preferred Units from the date of original issue. The cash distributions will be payable quarterly in arrears on January 15, April 15, July 15, and October 15 of each year, when, and if, declared by the board of directors. The initial distribution on the Class E Preferred Units will be payable on July 15, 2014 in an amount equal to \$0.67604 per unit, or approximately \$3.4 million. Thereafter, the Partnership will pay cumulative distributions in cash on the Class E Preferred Units on a quarterly basis at a rate of \$0.515625 per unit, or 8.25% per year. For the three months ended March 31, 2014, the Partnership allocated net income of \$0.4 million to the Class E Preferred Units for the dividends earned during the period, which was recorded as preferred unit dividends on its consolidated statements of operations.

At any time on or after March 17, 2019, or in the event of a liquidation or certain changes of control, the Partnership may redeem the Class E 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 on the date of redemption, whether or not declared. If the Partnership does not exercise this redemption right upon a change of control, then the holders of the Class E Preferred Units will have the option to convert their Class E Preferred Units into a number of the Partnership's common units, as set forth in the Certificate of Designation relating to the Class E Preferred Units.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 13) (in thousands):

	March 31, 2014	December 31, 2013	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	\$ 3,022,701	\$ 2,885,303	2 40
Rights of way	194,689	203,136	20 40
Buildings	10,291	10,291	40
Furniture and equipment	13,798	13,800	3 7
Other	15,559	15,805	3 10
	3,257,038	3,128,335	
Less accumulated depreciation	(431,725)	(404,143)	
	\$ 2,825,313	\$ 2,724,192	

The Partnership recorded depreciation expense on property, plant and equipment, including capital lease arrangements (see Note 13), of \$27.8 million and \$22.3 million for the three months ended March 31, 2014 and 2013, respectively, on its consolidated statements of operations.

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 was 5.5% and 6.1% for the three months ended March 31, 2014 and 2013, respectively. The amount of interest capitalized was \$2.8 million and \$2.5 million for the three months ended March 31, 2014 and 2013, respectively.

Table of Contents**NOTE 7 GOODWILL AND INTANGIBLE ASSETS**

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. Impairment testing for goodwill is done at the reporting unit level. A reporting unit is an operating segment or one level below an operating segment (also known as a component). A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available, and segment management regularly reviews the operating results of that component. The Partnership evaluates goodwill for impairment annually, on December 31 for all reporting units, except SouthTX, which will be evaluated on April 30. The following table reflects the carrying amounts of goodwill by reporting unit at March 31, 2014 and December 31, 2013 (in thousands):

	March 31, 2014	December 31, 2013
Carrying amount of goodwill by reporting unit:		
Barnett system	\$ 951	\$ 951
SouthOK system	170,381	170,381
SouthTX system	190,683	188,859
WestOK system	8,381	8,381
	\$ 370,396	\$ 368,572

The change in goodwill is related to a \$1.8 million increase in goodwill related to an adjustment of the fair value of assets acquired and liabilities assumed from the TEAK Acquisition (See Note 3). The Partnership expects all goodwill recorded to be deductible for tax purposes.

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at March 31, 2014 and December 31, 2013 (in thousands):

	March 31, 2014	December 31, 2013	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	\$ 3,419	\$ 3,419	2 10
Customer relationships	867,653	887,653	7 15
	871,072	891,072	
Accumulated amortization:			
Customer contracts	(904)	(779)	
Customer relationships	(215,384)	(194,022)	
	(216,288)	(194,801)	

Net carrying amount:		
Customer contracts	2,515	2,640
Customer relationships	652,269	693,631
Net carrying amount	\$ 654,784	\$ 696,271

The weighted-average amortization period for customer contracts and customer relationships is 9.5 years and 11.5 years, respectively. The Partnership recorded amortization expense on intangible assets of \$21.5 million and \$8.1 million for the three months ended March 31, 2014 and 2013, respectively, on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: remainder of 2014 - \$58.5 million; 2015 through 2016 - \$74.0 million per year; 2017 - \$68.0 million per year; 2018 - \$59.5 million.

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The valuation assessment for the TEAK Acquisition has not been completed as of March 31, 2014 and the estimates of fair value of goodwill and intangible assets with finite lives reflected as of March 31, 2014 are subject to change (see Note 3).

NOTE 8 OTHER ASSETS

The following is a summary of other assets (in thousands):

	March 31, 2014	December 31, 2013
Deferred finance costs, net of accumulated amortization of \$23,890 and \$22,034 at March 31, 2014 and December 31 2013, respectively	\$ 39,538	\$ 41,094
Security deposits	5,817	5,367
	\$ 45,355	\$ 46,461

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). The Partnership incurred \$0.3 million and \$13.0 million of deferred finance costs during the three months ended March 31, 2014 and 2013, respectively, related to various financing activities (see Note 13). During the three months ended March 31, 2013, the Partnership redeemed all of its outstanding \$365.8 million 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes) (see Note 13) and recognized \$5.3 million of accelerated amortization of deferred financing costs, included in loss on early extinguishment of debt on the Partnership's consolidated statement of operations. There was no accelerated amortization of deferred financing costs during the three months ended March 31, 2014. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was \$1.9 million and \$1.5 million for the three months ended March 31, 2014 and 2013, respectively, which is recorded within interest expense on the Partnership's consolidated statements of operations.

NOTE 9 INCOME TAXES

The Partnership owns APL Arkoma, Inc., a taxable subsidiary. The components of the federal and state income tax benefit of the Partnership's taxable subsidiary for the three months ended March 31, 2014 and 2013 are summarized as follows (in thousands):

	Three Months Ended March 31,	
	2014	2013
Income tax benefit:		
Federal	\$ (357)	\$ (8)
State	(41)	(1)
Total income tax benefit	\$ (398)	\$ (9)

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The components of net deferred tax liabilities as of March 31, 2014 and December 31, 2013 consist of the following (in thousands):

	March 31, 2014	December 31, 2013
Deferred tax assets:		
Net operating loss tax carryforwards and alternative minimum tax credits	\$ 15,499	\$ 14,900
Deferred tax liabilities:		
Excess of asset carrying value over tax basis	(48,391)	(48,190)
Net deferred tax liabilities	\$ (32,892)	\$ (33,290)

As of March 31, 2014, the Partnership had net operating loss carry forwards for federal income tax purposes of approximately \$40.1 million, which expire at various dates from 2029 to 2034. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 10 DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price risk management activities. The Partnership uses financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. Due to the right of setoff, 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.

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

Offsetting of Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
As of March 31, 2014:			
Long-term portion of derivative assets	\$ 5,336	\$ (2,127)	\$ 3,209
Current portion of derivative liabilities	2,082	(2,082)	
Total derivative assets, net	\$ 7,418	\$ (4,209)	\$ 3,209
As of December 31, 2013:			
Current portion of derivative assets	\$ 1,310	\$ (1,136)	\$ 174
Long-term portion of derivative assets	5,082	(2,812)	2,270
Current portion of derivative liabilities	1,612	(1,612)	
Long-term portion of derivative liabilities	949	(949)	
Total derivative assets, net	\$ 8,953	\$ (6,509)	\$ 2,444

Offsetting of Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
As of March 31, 2014:			
Long-term portion of derivative assets	\$ (2,127)	\$ 2,127	\$
Current portion of derivative liabilities	(15,869)	2,082	(13,787)
Total derivative liabilities, net	\$ (17,996)	\$ 4,209	\$ (13,787)

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As of December 31, 2013:

Current portion of derivative assets	\$ (1,136)	\$ 1,136	\$
Long-term portion of derivative assets	(2,812)	2,812	
Current portion of derivative liabilities	(12,856)	1,612	(11,244)
Long-term portion of derivative liabilities	(1,269)	949	(320)
Total derivative liabilities, net	\$ (18,073)	\$ 6,509	\$ (11,564)

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The following table summarizes the Partnership's commodity derivatives as of March 31, 2014, (fair value and volumes in thousands):

Production Period	Commodity	Volumes⁽¹⁾	Average Fixed Price (\$/Volume)	Fair Value⁽²⁾ Asset/ (Liability)
<u>Sold fixed price swaps</u>				
2014	Natural gas	12,690	\$ 4.03	\$ (5,555)
2015	Natural gas	18,610	4.24	592
2016	Natural gas	7,950	4.28	779
2017	Natural gas	600	4.46	23
2014	NGLs	60,354	1.20	(5,123)
2015	NGLs	41,076	1.08	(1,993)
2016	NGLs	6,300	1.03	(85)
2014	Crude oil	219	91.06	(1,672)
2015	Crude oil	60	85.13	(298)
Total fixed price swaps				(13,332)
<u>Purchased put options</u>				
2014	Natural gas	500	4.13	60
2014	NGLs	6,930	0.96	135
2015	NGLs	3,150	0.94	155
2014	Crude oil	267	90.41	657
2015	Crude oil	270	89.18	1,820
<u>Sold call options</u>				
2014	NGLs	3,780	1.32	(27)
2015	NGLs	1,260	1.28	(46)
Total options				2,754
Total derivatives				\$ (10,578)

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.

(2) See Note 11 for discussion on fair value methodology.

The following tables summarize the gross effect of all derivative instruments on the Partnership's consolidated statements of operations for the periods indicated (in thousands):

**For the Three Months Ended
March 31,
2014 2013**

Derivatives not designated as hedges		
Gain (loss) recognized in derivative loss, net:		
Commodity contract - realized ⁽¹⁾	\$ (9,835)	\$ 1,636
Commodity contract - unrealized ⁽²⁾	1,164	(13,719)
Derivative loss, net	\$ (8,671)	\$ (12,083)

- (1) Realized gain (loss) represents the gain or loss incurred when the derivative contract expires and/or is cash settled.
- (2) Unrealized gain (loss) represents the mark-to-market gain or loss recognized on open derivative contracts, which have not yet settled.

Table of Contents**NOTE 11 FAIR VALUE OF FINANCIAL INSTRUMENTS**

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. 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. These two types of inputs are further prioritized into the following hierarchy:

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.

Derivative Instruments

At March 31, 2014, the valuations for all the Partnership's derivative contracts are defined as Level 2 assets and liabilities within the same class of nature and risk, with the exception of the Partnership's NGL fixed price swaps and NGL options, which are defined as Level 3 assets and liabilities within the same class of nature and risk.

The Partnership's Level 2 commodity derivatives include natural gas and crude oil swaps and options, which are calculated based upon observable market data related to the change in price of the underlying commodity. These swaps and options are calculated by utilizing the New York Mercantile Exchange (NYMEX) quoted prices for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Valuations for the Partnership's NGL options are based on forward price curves developed by financial institutions, and therefore are defined as Level 3. The NGL options are over-the-counter instruments that are not actively traded in an open market, thus the Partnership utilizes the valuations provided by the financial institutions that provide the NGL options for trade. The Partnership tests these valuations for reasonableness through the use of an internal valuation model.

Valuations for the Partnership's NGL fixed price swaps are based on forward price curves provided by a third party, which the Partnership considers to be Level 3 inputs. The prices are adjusted based upon the relationship between the prices for the product/locations quoted by the third party and the underlying product/locations utilized for the swap contracts, as determined by a regression model of the historical settlement prices for the different product/locations. The regression model is recalculated on a quarterly basis. This adjustment is an unobservable Level 3 input. The NGL fixed price swaps are over-the-counter instruments which are not actively traded in an open market. However, the prices for the underlying products and locations do have a direct correlation to the prices for the products and locations provided by the third party, which are based upon trading activity for the products and locations quoted. A change in the relationship between these prices would have a direct impact upon the unobservable adjustment utilized to calculate the fair value of the NGL fixed price swaps.

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The following table represents the Partnership's derivative assets and liabilities recorded at fair value as of March 31, 2014 and December 31, 2013 (in thousands):

	Level 1	Level 2	Level 3	Total
March 31, 2014				
Assets				
Commodity swaps	\$	\$ 3,189	\$ 1,402	\$ 4,591
Commodity options		2,537	290	2,827
Total assets		5,726	1,692	7,418
Liabilities				
Commodity swaps		(9,320)	(8,603)	(17,923)
Commodity options			(73)	(73)
Total liabilities		(9,320)	(8,676)	(17,996)
Total derivatives	\$	\$ (3,594)	\$ (6,984)	\$ (10,578)
December 31, 2013				
Assets				
Commodity swaps	\$	\$ 2,994	\$ 1,412	\$ 4,406
Commodity options		4,337	210	4,547
Total assets		7,331	1,622	8,953
Liabilities				
Commodity swaps		(4,695)	(13,378)	(18,073)
Total liabilities		(4,695)	(13,378)	(18,073)
Total derivatives	\$	\$ 2,636	\$ (11,756)	\$ (9,120)

The Partnership's Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership's Level 3 derivative instruments for the three months ended March 31, 2014 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		NGL Call Options		Total Amount
	Gallons	Amount	Gallons	Amount	Gallons	Amount	
Balance December 31, 2013	130,158	\$ (11,966)	6,300	\$ 210		\$	\$ (11,756)
New contracts ⁽¹⁾			5,040	200	5,040	(200)	
	(22,428)	5,873	(1,260)	137			6,010

Cash settlements from unrealized gain (loss) ⁽²⁾⁽³⁾								
Net change in unrealized gain (loss) ⁽²⁾			(1,108)		(120)		127	(1,101)
Deferred option premium recognition ⁽³⁾								
					(137)			(137)
Balance	March 31, 2014		107,730	\$ (7,201)	10,080	\$ 290	5,040	\$ (73) \$ (6,984)

- (1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.
- (2) Included within derivative gain (loss), net on the Partnership's consolidated statements of operations.
- (3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

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The following table provides a summary of the unobservable inputs used in the fair value measurement of the Partnership's NGL fixed price swaps at March 31, 2014 and December 31, 2013 (in thousands):

	Gallons	Third Party Quotes ⁽¹⁾	Adjustments ⁽²⁾	Total Amount
As of March 31, 2014				
Propane swaps	83,538	\$ (6,059)	\$	\$ (6,059)
Isobutane swaps	5,040	(1,405)	651	(754)
Normal butane swaps	5,040	483	192	675
Natural gasoline swaps	14,112	(276)	(787)	(1,063)
Total NGL swaps March 31, 2014	107,730	\$ (7,257)	\$ 56	\$ (7,201)
As of December 31, 2013				
Propane swaps	100,296	\$ (10,260)	\$	\$ (10,260)
Isobutane swaps	6,300	(2,342)	955	(1,387)
Normal butane swaps	7,560	40	322	362
Natural gasoline swaps	16,002	132	(813)	(681)
Total NGL swaps December 31, 2013	130,158	\$ (12,430)	\$ 464	\$ (11,966)

- (1) Based upon the difference between the quoted market price provided by the third party and the fixed price of the swap.
- (2) Product and location basis differentials calculated through the use of a regression model, which compares the difference between the settlement prices for the products and locations quoted by the third party and the settlement prices for the actual products and locations underlying the derivatives, using a three year historical period.

The following table provides a summary of the regression coefficient utilized in the calculation of the unobservable inputs for the Level 3 fair value measurements for the NGL fixed price swaps for the periods indicated (in thousands):

	Level 3 NGL Swap Fair Value Adjustments	Adjustment based upon Regression Coefficient		
		Lower 95%	Upper 95%	Average
As of March 31, 2014:				
Isobutane	\$ 651	1.1168	1.1271	1.1219
Normal butane	192	1.0341	1.0382	1.0361
Natural gasoline	(787)	0.9685	0.9716	0.9701
Total Level 3 adjustments March 31, 2014	\$ 56			

As of December 31, 2013:

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Isobutane		\$	955	1.1184	1.1284	1.1234
Normal butane			322	1.0341	1.0386	1.0364
Natural gasoline			(813)	0.9727	0.9751	0.9739
Total Level 3 adjustments	December 31, 2013	\$	464			

Table of Contents*NGL Linefill*

The Partnership had \$21.7 million and \$14.5 million of NGL linefill at March 31, 2014 and December 31, 2013, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties, for which the counterparty will pay at a designated later period at a price determined by the then market price. The Partnership's NGL linefill held by some counterparties will be settled at various periods in the future and is defined as a Level 3 asset, which is valued using the same forward price curve utilized to value the Partnership's NGL fixed price swaps. The product/location adjustment based upon the multiple regression analysis, which was included in the value of the linefill, was a reduction of \$0.4 million and \$0.4 million as of March 31, 2014 and December 31, 2013, respectively. The Partnership's NGL linefill held by other counterparties is adjusted on a monthly basis according to the volumes delivered to the counterparties each period and is valued on a first in first out (FIFO) basis.

The following table provides a summary of changes in fair value of the Partnership's NGL linefill for the three months ended March 31, 2014 (in thousands):

	Linefill Valued at Market		Linefill Valued on FIFO		Total NGL Linefill	
	Gallons	Amount	Gallons	Amount	Gallons	Amount
Balance December 31, 2013	5,788	\$ 4,739	11,538	\$ 9,778	17,326	\$ 14,517
Deliveries into NGL linefill	1,050	1,013	25,600	16,875	26,650	17,888
NGL linefill sales			(20,622)	(10,847)	(20,622)	(10,847)
Net change in NGL linefill valuation ⁽¹⁾		143				143
Balance March 31, 2014	6,838	\$ 5,895	16,516	\$ 15,806	23,354	\$ 21,701

(1) Included within natural gas and liquids sales on the Partnership's consolidated statements of operations.

Contingent Consideration

In February 2012, the Partnership acquired a gas gathering system and related assets for an initial net purchase price of \$19.0 million. The Partnership agreed to pay up to an additional \$12.0 million in contingent payments, payable in two equal amounts, if certain volumes are achieved on the acquired gathering system within a specified time period. Sufficient volumes were achieved in December 2012 and the Partnership paid the first contingent payment of \$6.0 million in January 2013. As of March 31, 2014, the fair value of the remaining contingent payment resulted in a \$6.0 million long term liability, which was recorded within other long term liabilities on the Partnership's consolidated balance sheets. The range of the undiscounted amount the Partnership could pay related to the remaining contingent payment is between \$0.0 and \$6.0 million.

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 the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership's current assets and liabilities on its consolidated balance sheets, other than the derivatives, NGL linefill and contingent consideration discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts

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due to their short-term nature and thus are categorized as Level 1 values. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value and thus is categorized as a Level 1 value. The estimated fair value of the Partnership's Senior Notes (see Note 13) is based upon the market approach and calculated using the yield of the Senior Notes as provided by financial institutions and thus is categorized as a Level 3 value. The estimated fair values of the Partnership's total debt at March 31, 2014 and December 31, 2013, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were \$1,708.6 million and \$1,663.6 million, respectively, compared with the carrying amounts of \$1,704.9 million and \$1,707.3 million, respectively.

Acquisitions

On May 7, 2013, the Partnership completed the TEAK Acquisition (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. These inputs require significant judgments and estimates at the time of the valuation. The estimates of fair value of the TEAK assets as of the acquisition date, which are reflected in the Partnership's consolidated balance sheet as of March 31, 2014, are subject to change as the final valuation has not yet been completed (see Note 3).

NOTE 12 ACCRUED LIABILITIES

The following is a summary of accrued liabilities (in thousands):

	March 31, 2014	December 31, 2013
Accrued capital expenditures	\$ 10,295	\$ 17,898
Acquisition-related liabilities	8,914	8,933
Accrued ad valorem and production taxes	8,795	3,551
Other	14,455	17,067
	\$ 42,459	\$ 47,449

NOTE 13 DEBT

Total debt consists of the following (in thousands):

	March 31, 2014	December 31, 2013
Revolving credit facility	\$ 150,000	\$ 152,000
6.625% Senior notes due 2020	504,387	504,556
5.875% Senior notes due 2023	650,000	650,000
4.750% Senior notes due 2021	400,000	400,000
Capital lease obligations	556	754
Total debt	1,704,943	1,707,310

Less current maturities	(394)	(524)
Total long term debt	\$ 1,704,549	\$ 1,706,786

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Cash payments for interest related to debt, net of capitalized interest, were \$34.7 million and \$22.1 million for the three months ended March 31, 2014 and 2013, respectively.

Revolving Credit Facility

At March 31, 2014, the Partnership had a \$600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. The weighted average interest rate for borrowings on the revolving credit facility, at March 31, 2014, was 3.2%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$0.1 million was outstanding at March 31, 2014. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At March 31, 2014, the Partnership had \$449.9 million of remaining committed capacity under its revolving credit facility.

The events that constitute an event of default for the revolving credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the General Partner.

On March 11, 2014, the Partnership entered into an amendment to the credit agreement governing the revolving credit facility which, among other changes:

adjusted the duration of, and maximum ratios allowed during, the Acquisition Period, as defined in the credit agreement, for the Consolidated Funded Debt Ratio, as defined in the credit agreement; and

permitted the payment of cash distributions, if any, on the Class E Preferred Units so long as the Partnership has a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to \$50 million.

As of March 31, 2014, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At March 31, 2014, the Partnership had \$500.0 million principal outstanding of 6.625% unsecured senior notes due October 1, 2020 (6.625% Senior Notes), \$650.0 million principal outstanding of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes), and \$400.0 million of 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes and with the 6.625% Senior Notes and 5.875% Senior Notes, the Senior Notes). The 6.625% Senior Notes are presented combined with a net \$4.4 million unamortized premium as of March 31, 2014.

Indentures governing the Senior Notes contain covenants, including limitations of the Partnership's ability to: incur certain liens; engage in sale/leaseback transactions; 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 its assets. The Partnership is in compliance with these covenants as of March 31, 2014.

5.875% Senior Notes

On February 11, 2013, the Partnership issued \$650.0 million of the 5.875% Senior Notes in a private placement transaction. The 5.875% Senior Notes were issued at par. The Partnership received net proceeds of \$637.3 million

after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the credit facility.

Table of Contents**8.75% Senior Notes**

On January 28, 2013, the Partnership commenced a cash tender offer for any and all of its outstanding 8.75% Senior Notes and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default contained in the indenture governing the 8.75% Senior Notes (8.75% Senior Notes Indenture). Approximately \$268.4 million aggregate principal amount of the 8.75% Senior Notes were validly tendered as of the expiration date of the consent solicitation. In February 2013, the Partnership accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and paid \$291.4 million to redeem the \$268.4 million principal plus \$11.2 million make-whole premium, \$3.7 million accrued interest and \$8.0 million consent payment. The Partnership entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture.

On March 12, 2013, the Partnership paid \$105.6 million to redeem the remaining \$97.3 million 8.75% Senior Notes not purchased in connection with the tender offer, plus a \$6.3 million make-whole premium and \$2.0 million in accrued interest. The Partnership funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

Capital Leases

The following is a summary of the leased property under capital leases as of March 31, 2014 and December 31, 2013, which are included within property, plant and equipment (see Note 6) (in thousands):

	March 31, 2014	December 31, 2013
Pipelines, processing and compression facilities	\$ 1,142	\$ 2,281
Less accumulated depreciation	(144)	(330)
	\$ 998	\$ 1,951

In March 2014, the Partnership took ownership of \$1.1 million of facilities in connection with the conclusion of a capital lease. Depreciation expense for leased properties was \$32 thousand and \$211 thousand for the three months ended March 31, 2014 and 2013, respectively, which is included within depreciation and amortization expense on the Partnership's consolidated statements of operations (see Note 6).

NOTE 14 COMMITMENTS AND CONTINGENCIES

The Partnership has certain long-term unconditional purchase obligations and commitments, consisting primarily of transportation contracts. These agreements provide for transportation services to be used in the ordinary course of the Partnership's operations. Transportation fees paid related to these contracts, including minimum shipment payments, were \$7.3 million and \$3.0 million for the three months ended March 31, 2014 and 2013, respectively. The future fixed and determinable portion of the obligations as of March 31, 2014 was as follows: remainder of 2014 - \$6.3 million; 2015 to 2017 - \$3.5 million per year; and 2018 - \$2.7 million.

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The Partnership had committed approximately \$74.0 million for the purchase of property, plant and equipment at March 31, 2014.

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on its financial condition or results of operations.

NOTE 15 BENEFIT PLANS

Long-Term Incentive Plans

The Partnership has a 2004 Long-Term Incentive Plan (2004 LTIP) and a 2010 Long-Term Incentive Plan (2010 LTIP and collectively with the 2004 LTIP, the LTIPs) in which officers, employees, non-employee managing board members of the General Partner, employees of the General Partner's affiliates and consultants are eligible to participate. The LTIPs are administered by the compensation committee appointed by the General Partner's managing board (the Compensation Committee). Under the LTIPs, the Compensation Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At March 31, 2014, the Partnership had 1,664,642 phantom units outstanding under the Partnership's LTIPs, with 608,369 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options that have vested and have been exercised.

Partnership Phantom Units

Through March 31, 2014, phantom units granted to employees under the LTIPs generally had vesting periods of four years. However, in February 2014, the Partnership granted 227,000 phantom units, which had a vesting period of three years. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards to non-employee members of the board automatically vest upon a change of control, as defined in the LTIPs. At March 31, 2014, there were 531,244 phantom units outstanding under the LTIPs that will vest within the following twelve months.

All phantom units outstanding under the LTIPs at March 31, 2014 include distribution equivalent rights (DERs), which is the right to receive cash per phantom unit in an amount equal to and at the same time as the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. The DERs were granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were \$0.9 million and \$0.6 million during the three months ended March 31, 2014 and 2013, respectively. These amounts were recorded as reductions of equity on the Partnership's consolidated balance sheets.

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The following table sets forth the Partnership's LTIPs phantom unit activity for the periods indicated:

	Three Months Ended 31,			
	2014		2013	
	Number of Units	Fair Value⁽¹⁾	Number of Units	Fair Value⁽¹⁾
Outstanding, beginning of period	1,446,553	\$ 36.32	1,053,242	\$ 33.21
Granted	234,701	31.03	6,804	33.06
Forfeited	(2,200)	39.51		
Matured and issued ⁽²⁾⁽³⁾	(14,412)	34.03	(2,963)	28.94
Outstanding, end of period⁽⁴⁾	1,664,642	\$ 35.59	1,057,083	\$ 33.22
Non-cash compensation expense recognized (in thousands)		\$ 6,439		\$ 4,384

(1) Fair value based upon weighted average grant date price.

(2) The intrinsic values for phantom unit awards exercised during the three months ended March 31, 2014 and 2013 were \$0.5 million and \$0.1 million, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at March 31, 2014 and December 31, 2013 was \$53.5 million and \$50.7 million, respectively.

(4) There were 25,228 and 22,539 outstanding phantom unit awards at March 31, 2014 and December 31, 2013, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.

At March 31, 2014, the Partnership had approximately \$31.5 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.0 years.

NOTE 16 RELATED PARTY TRANSACTIONS

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of ATLS. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to its employees who perform services for the Partnership based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by ATLS based on the number of its employees who devote their time to activities on the Partnership's behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates \$1.3 million and \$1.3 million for the three months ended March 31, 2014 and 2013, respectively, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the three months ended March 31, 2014 and

2013. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

The Partnership compresses and gathers gas for Atlas Resource Partners, L.P. (NYSE: ARP) (ARP) on its gathering systems located in Tennessee. ARP's general partner is wholly-owned by ATLS, and two members of the General Partner's managing board are members of ARP's board of directors. The Partnership entered into an agreement to provide these services, which extends for the life of ARP's leases, in February 2008. The Partnership charged ARP approximately \$0.1 million and \$0.1 million in compression and gathering fees for the three months ended March 31, 2014 and 2013, respectively.

Table of Contents**NOTE 17 SEGMENT INFORMATION**

The Partnership has two reportable segments: Gathering and Processing; and Transportation, Treating and Other (Transportation and Treating). These reportable segments reflect the way the Partnership manages its operations.

The Gathering and Processing segment consists of (1) the SouthOK, SouthTX, WestOK and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma and Permian Basins and the Eagle Ford Shale play in south Texas; and (2) the natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas.

The Transportation and Treating segment consists of (1) the gas treating operations, which own contract gas treating facilities located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford; and (2) certain subsidiaries 20% interest in the equity income generated by WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Gas treating revenues are primarily derived from monthly lease fees for use of the treating facilities. Pipeline revenues are primarily derived from transportation fees.

The following summarizes the Partnership's reportable segment data for the periods indicated (in thousands):

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Three Months Ended March 31, 2014:				
Revenue:				
Revenues third party ⁽¹⁾	\$ 707,774	\$ 1,201	\$ (9,026)	\$ 699,949
Revenues affiliates	55			55
Total revenues	707,829	1,201	(9,026)	700,004
Costs and Expenses:				
Operating costs and expenses	600,227	369		600,596
General and administrative ⁽¹⁾			17,940	17,940
Other costs			37	37
Depreciation and amortization	48,227	760	252	49,239
Interest expense ⁽¹⁾			23,663	23,663
Total costs and expenses	648,454	1,129	41,892	691,475
Equity income (loss) in joint ventures	(3,605)	1,727		(1,878)
Income (loss) before tax	55,770	1,799	(50,918)	6,651
Income tax benefit	(398)			(398)
Net income (loss)	\$ 56,168	\$ 1,799	\$ (50,918)	\$ 7,049

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	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Three Months Ended March 31, 2013:				
Revenue:				
Revenues third party ⁽¹⁾	\$ 418,607	\$ 1,433	\$ (12,199)	\$ 407,841
Revenues affiliates	71			71
Total revenues	418,678	1,433	(12,199)	407,912
Costs and Expenses:				
Operating costs and expenses	347,055	344		347,399
General and administrative ⁽¹⁾			13,798	13,798
Other costs			530	530
Depreciation and amortization	29,971	268	219	30,458
Interest expense ⁽¹⁾			18,686	18,686
Total costs and expenses	377,026	612	33,233	410,871
Equity income in joint ventures		2,040		2,040
Loss on early extinguishment of debt			(26,582)	(26,582)
Income (loss) before tax	41,652	2,861	(72,014)	(27,501)
Income tax benefit	(9)			(9)
Net income (loss)	\$ 41,661	\$ 2,861	\$ (72,014)	\$ (27,492)

- (1) Derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

	Three Months Ended March 31,	
	2014	2013
Capital Expenditures:		
Gathering and processing	\$ 127,915	\$ 108,393
Transportation and treating		123
Corporate and other	416	
	\$ 128,331	\$ 108,516
Balance Sheet		
Equity method investment in joint ventures:		
Gathering and processing	\$ 183,541	\$ 162,511

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Transportation and treating	85,517	85,790
	\$ 269,058	\$ 248,301
Goodwill:		
Gathering and processing	\$ 370,396	\$ 368,572
Total assets:		
Gathering and processing	\$ 4,266,976	\$ 4,146,314
Transportation and treating	130,932	132,152
Corporate and other	49,050	49,379
	\$ 4,446,958	\$ 4,327,845

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The following table summarizes the Partnership's natural gas and liquids sales by product or service for the periods indicated (in thousands):

	Three Months Ended March 31,	
	2014	2013
Natural gas and liquids sales:		
Natural gas	\$ 271,052	\$ 141,484
NGLs	360,754	217,831
Condensate	31,181	24,565
Other	143	(32)
Total	\$ 663,130	\$ 383,848

Table of Contents**NOTE 18 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION**

The Partnership's Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership's consolidated financial statements as of March 31, 2014 and December 31, 2013 and for the three months ended March 31, 2014 and 2013 include the financial statements of WestOK LLC, WestTX LLC and Centrahoma, as well as the equity income received by two of the Partnership's subsidiaries in WTLPG and the T2 Joint Ventures. Under the terms of the Senior Notes and the revolving credit facility, WestOK LLC, WestTX LLC and Centrahoma are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership's stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership's consolidated accounts as of March 31, 2014 and December 31, 2013 and for the three months ended March 31, 2014 and 2013. For the purpose of the following financial information, the Partnership's investments in its subsidiaries and the guarantor subsidiaries' investments in their subsidiaries are presented in accordance with the equity method of accounting (in thousands):

Balance Sheets	Non-				
	Parent	Guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
March 31, 2014					
Assets					
Cash and cash equivalents	\$	\$ 168	\$ 9,588	\$	\$ 9,756
Accounts receivable affiliates		95,903		(95,903)	
Other current assets	204	44,469	225,365	(951)	269,087
Total current assets	204	140,540	234,953	(96,854)	278,843
Property, plant and equipment, net		760,038	2,065,275		2,825,313
Intangible assets, net		568,491	86,293		654,784
Goodwill		325,502	44,894		370,396
Equity method investment in joint ventures			269,058		269,058
Long term portion of derivative assets		3,209			3,209
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	3,962,561	996,504		(4,959,065)	
Other assets, net	39,538	1,787	4,030		45,355
Total assets	\$ 4,002,303	\$ 2,796,071	\$ 4,557,431	\$ (6,908,847)	\$ 4,446,958
Liabilities and Equity					
Accounts payable affiliates	\$ 26,732	\$	\$ 76,260	\$ (95,903)	\$ 7,089
Other current liabilities	14,084	83,182	252,574		349,840
Total current liabilities	40,816	83,182	328,834	(95,903)	356,929
Long-term debt, less current portion	1,704,387	162			1,704,549

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Deferred income taxes, net		32,892			32,892
Other long-term liability	144	1,033	6,000		7,177
Equity	2,256,956	2,678,802	4,222,597	(6,812,944)	2,345,411
Total liabilities and equity	\$ 4,002,303	\$ 2,796,071	\$ 4,557,431	\$ (6,908,847)	\$ 4,446,958

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December 31, 2013	Non-				
	Parent	Guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	\$	\$ 168	\$ 4,746	\$	\$ 4,914
Accounts receivable affiliates	765,236			(765,236)	
Other current assets	215	52,910	185,975	(2,236)	236,864
Total current assets	765,451	53,078	190,721	(767,472)	241,778
Property, plant and equipment, net		723,302	2,000,890		2,724,192
Intangible assets, net		603,533	92,738		696,271
Goodwill		323,678	44,894		368,572
Equity method investment in joint venture			248,301		248,301
Long term portion of derivative assets		2,270			2,270
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	3,186,938	1,487,358		(4,674,296)	
Other assets, net	41,094	1,787	3,580		46,461
Total assets	\$ 3,993,483	\$ 3,195,006	\$ 4,434,052	\$ (7,294,696)	\$ 4,327,845
Liabilities and Equity					
Accounts payable affiliates	\$	\$ 423,078	\$ 345,070	\$ (765,236)	\$ 2,912
Other current liabilities	26,819	75,031	215,464		317,314
Total current liabilities	26,819	498,109	560,534	(765,236)	320,226
Long-term portion of derivative liabilities		320			320
Long-term debt, less current portion	1,706,556	230			1,706,786
Deferred income taxes, net		33,290			33,290
Other long-term liability	203	1,115	6,000		7,318
Equity	2,259,905	2,661,942	3,867,518	(6,529,460)	2,259,905
Total liabilities and equity	\$ 3,993,483	\$ 3,195,006	\$ 4,434,052	\$ (7,294,696)	\$ 4,327,845

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Statements of Operations	Non-				
	Parent	Guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended March 31, 2014					
Total revenues	\$	\$ 146,836	\$ 556,538	\$ (3,370)	\$ 700,004
Total costs and expenses	(23,805)	(171,864)	(499,176)	3,370	(691,475)
Equity income (loss)	28,392	53,021	(1,878)	(81,413)	(1,878)
Income (loss), before tax	4,587	27,993	55,484	(81,413)	6,651
Income tax benefit		(398)			(398)
Net income (loss)	4,587	28,391	55,484	(81,413)	7,049
Income attributable to non-controlling interest			(2,462)		(2,462)
Preferred unit imputed dividend effect	(11,378)				(11,378)
Preferred unit dividends in kind	(9,719)				(9,719)
Preferred unit dividends	(406)				(406)
Net income (loss) attributable to common limited partners and the General Partner	\$ (16,916)	\$ 28,391	\$ 53,022	\$ (81,413)	\$ (16,916)
Three Months Ended March 31, 2013					
Total revenues	\$	\$ 91,841	\$ 335,372	\$ (19,301)	\$ 407,912
Total costs and expenses	(18,596)	(114,227)	(297,349)	19,301	(410,871)
Equity income (loss)	16,317	38,695		(52,972)	2,040
Loss on early extinguishment of debt	(26,582)				(26,582)
Income (loss), before tax	(28,861)	16,309	38,023	(52,972)	(27,501)
Income tax benefit		(9)			(9)
Net income (loss)	(28,861)	16,318	38,023	(52,972)	(27,492)
Income attributable to non-controlling interest			(1,369)		(1,369)
Net income (loss) attributable to common limited partners and the General Partner	\$ (28,861)	\$ 16,318	\$ 36,654	\$ (52,972)	\$ (28,861)

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Statements of Cash Flows	Non-				
	Parent	Guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended March 31, 2014					
Net cash provided by (used in):					
Operating activities	\$ 92,913	\$ 66,817	\$ 77,780	\$ (171,342)	\$ 66,168
Investing activities	(162,469)	(149,327)	(103,658)	284,770	(130,684)
Financing activities	69,556	82,510	30,720	(113,428)	69,358
Net change in cash and cash equivalents			4,842		4,842
Cash and cash equivalents, beginning of period		168	4,746		4,914
Cash and cash equivalents, end of period	\$	\$ 168	\$ 9,588	\$	\$ 9,756

Statements of Cash Flows	Non-				
	Parent	Guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended March 31, 2013					
Net cash provided by (used in):					
Operating activities	\$ (58,592)	\$ 33,933	\$ 62,426	\$ 3,489	\$ 41,256
Investing activities	(21,541)	(2,534)	(105,856)	21,541	(108,390)
Financing activities	80,133	(31,399)	48,293	(25,030)	71,997
Net change in cash and cash equivalents			4,863		4,863
Cash and cash equivalents, beginning of period		157	3,241		3,398
Cash and cash equivalents, end of period	\$	\$ 157	\$ 8,104	\$	\$ 8,261

NOTE 19 SUBSEQUENT EVENTS

On April 22, 2014, the Partnership declared a cash distribution of \$0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2014. The \$56.1 million distribution, including \$6.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on May 15, 2014 to unitholders of record at the close of business on May 8, 2014 (see Note 5). Based on this declaration, the Partnership will also issue approximately 317,000 Class D Preferred Units to the holders of the Class D Preferred Units as a preferred unit distribution in kind for the quarter ended March 31, 2014.

On May 5, 2014, the Partnership announced that it had entered into a definitive agreement to sell its subsidiaries holding interests in WTLPG to a subsidiary of Martin Midstream Partners L.P. for \$135.0 million in cash, subject to certain closing adjustments. The proceeds will be used to pay down the revolving credit facility.

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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, under the caption **Risk Factors**, in our Annual Report on Form 10-K for the year ended December 31, 2013. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

The following discussion provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with our consolidated financial statements and related notes thereto appearing elsewhere in this report and with our Annual Report on Form 10-K for the year ended December 31, 2013.

General

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol **APL**. We are a leading provider of natural gas gathering, processing and treating services in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States; a provider of natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and a provider of NGL transportation services in the southwestern region of the United States.

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Gathering and Processing; and Transportation, Treating and Other (Transportation and Treating).

The Gathering and Processing segment consists of (1) the SouthOK, SouthTX, WestOK and WestTX operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma and Permian Basins and the Eagle Ford Shale play in south Texas; and (2) natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering and processing of natural gas.

As of March 31, 2014, our Gathering and Processing operations own, have interests in and operate fourteen natural gas processing plants with aggregate capacity of approximately 1,500 MMCFD located in Oklahoma and Texas; a gas treating facility located in Oklahoma; and approximately 11,200 miles of active natural gas gathering systems located in Oklahoma, Kansas, Tennessee and Texas. Our gathering systems gather natural gas from oil and natural gas wells and central delivery points and deliver to this gas to processing plants, as well as third-party pipelines.

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Our Gathering and Processing operations are all located in or near areas of abundant and long-lived natural gas production, including the Golden Trend, Mississippian Limestone and Hugoton field in the Anadarko Basin; the Woodford Shale; the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin; the Barnett Shale; and the Eagle Ford Shale. Our gathering systems are connected to primarily individual well connections and, secondarily, central delivery points, which are linked to multiple wells. We believe we have significant scale in each of our primary service areas. We provide gathering, processing and treating services to the wells connected to our systems, primarily under long-term contracts. As a result of the location and capacity of our gathering, processing and treating assets, we believe we are strategically positioned to capitalize on the drilling activity in our service areas.

Our Transportation and Treating segment consists of (1) our gas treating operations; and (2) two subsidiaries 20% interest in WTLPG. Our gas treating operations include 17 gas treating facilities used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas; and are located in various shale plays, including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (NYSE: CVX), which owns the remaining 80% interest; and owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Gas Treating revenues are primarily derived from monthly lease fees for use of treating facilities. Pipeline revenues are primarily derived from transportation fees.

Recent Events

On March 11, 2014, we entered into an amendment to the credit agreement governing our revolving credit facility which, among other changes:

adjusted the duration of, and maximum ratios allowed during, the Acquisition Period, as defined in the credit agreement, for the Consolidated Funded Debt Ratio, as defined in the credit agreement; and

permitted the payment of cash distributions, if any, on the Class E cumulative redeemable perpetual preferred units (Class E Preferred Units) so long as we have a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to \$50 million.

On March 17, 2014, we issued 5,060,000 of our Class E Preferred Units to the public at an offering price of \$25.00 per Class E Preferred Unit. We received \$122.4 million in net proceeds. The proceeds were used to pay down the revolving credit facility (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Equity).

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Subsequent Events

On April 22, 2014, we declared a cash distribution of \$0.62 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2014. The \$56.1 million distribution, including \$6.1 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on May 15, 2014 to unitholders of record at the close of business on May 8, 2014 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Equity). Based on this declaration, we will also distribute approximately 317,000 Class D convertible preferred units (Class D Preferred Units) to the holders of the Class D Preferred Units as a preferred unit distribution for the quarter ended March 31, 2014.

On May 5, 2014, we announced that we have entered into a definitive agreement to sell our subsidiaries holding interests in WTLPG to a subsidiary of Martin Midstream Partners L.P. for \$135.0 million in cash, subject to certain closing adjustments. The proceeds will be used to pay down the revolving credit facility.

How We Evaluate Our Operations

Our principal revenue is generated from the gathering, processing and treating of natural gas; the sale of natural gas, NGLs and condensate; the transportation of NGLs; and the leasing of gas treating facilities. Our profitability is a function of the difference between the revenues we receive and the costs associated with conducting our operations, including the cost of natural gas, NGLs and condensate we purchase as well as operating and general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Variables that affect our profitability are:

the volumes of natural gas we gather, process and treat, which in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas the wells produce, and the demand for natural gas, NGLs and condensate;

the price of the natural gas we gather; process and treat; and the NGLs and condensate we recover and sell, which is a function of the relevant supply and demand in the mid-continent and northeastern areas of the United States;

the NGL and BTU content of the gas gathered and processed;

the contract terms with each producer; and

the efficiency of our gathering systems and processing and treating plants.

Our management uses a variety of financial measures and operational measurements other than our GAAP financial statements to analyze our performance. These include: (1) volumes, (2) operating expenses and (3) the following non-GAAP measures gross margin, EBITDA, adjusted EBITDA and distributable cash flow. Our management views these measures as important performance measures of core profitability for our operations and as key components of our internal financial reporting. We believe investors benefit from having access to the same financial measures that

our management uses.

Volumes. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our gathering, processing and treating systems. This is achieved by connecting new wells and adding new volumes in existing areas of production. Our performance at our plants is also significantly impacted by the quality of the natural gas we process, the NGL content of the natural gas and the plant's recovery capability. In addition, we monitor fuel consumption and losses because they have a significant impact on the gross margin realized from our processing operations.

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Operating Expenses. Plant operating, transportation and compression expenses generally include the costs required to operate and maintain our pipelines and processing facilities, including salaries and wages, repair and maintenance expense, ad valorem taxes and other overhead costs.

Gross Margins. We define gross margin as natural gas and liquids sales revenue plus transportation, processing and other fee revenues less purchased product costs, subject to certain non-cash adjustments. Product costs include the cost of natural gas, NGLs and condensate we purchase from third parties. Gross margin, as we define it, does not include plant operating expenses; transportation and compression expenses; and derivative gain (loss) related to undesignated hedges, as movements in gross margin generally do not result in directly correlated movements in these categories.

Gross margin is a non-GAAP measure. The GAAP measure most directly comparable to gross margin is net income. Gross margin is not an alternative to GAAP net income and has important limitations as an analytical tool. Investors should not consider gross margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of gross margin may not be comparable to gross margin measures of other companies, thereby diminishing its utility.

EBITDA and Adjusted EBITDA. EBITDA represents net income (loss) before interest expense, income taxes, depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances, principally to directors and employees, impairment charges and other cash items such as non-recurring cash derivative early termination expense. The GAAP measure most directly comparable to EBITDA and Adjusted EBITDA is net income. EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies. The Adjusted EBITDA calculation is similar to the Consolidated EBITDA calculation utilized within the financial covenants under our credit facility, with the exception that Adjusted EBITDA includes certain non-cash items specifically excluded under our credit facility and excludes the capital expansion add back included in Consolidated EBITDA as defined in the credit facility (see [Revolving Credit Facility](#)).

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity's financial performance, such as cost of capital and historic costs of depreciable assets. We have included information concerning EBITDA and Adjusted EBITDA because they provide investors and management with additional information to better understand our operating performance and are presented solely as a supplemental financial measure. EBITDA and Adjusted EBITDA should not be considered as alternatives to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as indicators of our operating performance or liquidity. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our unit holders.

Distributable Cash Flow. We define distributable cash flow as net income plus tax, depreciation and amortization; amortization of deferred financing costs included in interest expense; and non-cash gain (losses) on derivative contracts, less income attributable to non-controlling interests, preferred unit dividends, maintenance capital expenditures, gains (losses) on asset sales and other non-cash gains (losses).

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Distributable cash flow is a significant performance metric used by our management and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can compute the ratio of distributable cash flow per unit to the declared cash distribution per unit to determine the rate at which the distributable cash flow covers the distribution. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships because the value of a unit of such an entity is generally determined by the unit's yield, which in turn is based on the amount of cash distributions the entity pays to a unitholder.

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income or GAAP cash flows from operating activities. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Table of Contents**Non-GAAP Financial Measures**

The following tables reconcile the non-GAAP financial measurements used by management to their most directly comparable GAAP measures for the three months ended March 31, 2014 and 2013 (in thousands):

RECONCILIATION OF GROSS MARGIN

	Three Months Ended March 31,	
	2014	2013
Net income (loss)	\$ 7,049	\$ (27,492)
Adjustments:		
Derivative loss, net	8,671	12,083
Other income, net	(2,108)	(3,422)
Operating expenses ⁽¹⁾	25,165	22,389
General and administrative expense ⁽²⁾	17,940	13,798
Depreciation and amortization	49,239	30,458
Interest	23,663	18,686
Income tax benefit	(398)	(9)
Equity (income) loss in joint ventures	1,878	(2,040)
Loss on early extinguishment of debt		26,582
Non-cash linefill (gain) loss ⁽³⁾	(143)	32
Gross margin	\$ 130,956	\$ 91,065

(1) Operating expenses include plant operating expenses; transportation and compression expenses; and other costs.

(2) General and administrative includes compensation reimbursement to affiliates.

(3) Represents the non-cash impact of commodity price movements on pipeline linefill.

Table of Contents**RECONCILIATION OF EBITDA, ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW**

	Three Months Ended March 31,	
	2014	2013
Net income (loss)	\$ 7,049	\$ (27,492)
Adjustments:		
Interest expense	23,663	18,686
Income tax benefit	(398)	(9)
Depreciation and amortization	49,239	30,458
EBITDA	79,553	21,643
Adjustments:		
Income attributable to non-controlling interests ⁽¹⁾	(2,462)	(1,369)
Non-controlling interest depreciation, amortization and interest expense ⁽²⁾	(706)	(850)
Equity (income) loss in joint ventures	1,878	(2,040)
Distributions from joint ventures	2,000	1,800
Loss on early extinguishment of debt		26,582
Non-cash (gain) loss on derivatives	(1,164)	13,719
Premium expense on derivative instruments	2,623	3,275
Acquisition costs	37	530
Non-cash compensation	6,439	4,384
Non-cash line fill (gain) loss ⁽³⁾	(143)	32
Minimum volume adjustment ⁽⁴⁾	2,749	
Adjusted EBITDA	90,804	67,706
Adjustments:		
Interest expense	(23,663)	(18,686)
Preferred dividend obligation	(406)	
Amortization of deferred finance costs	1,856	1,544
Premium expense on derivative instruments	(2,623)	(3,275)
Maintenance capital, net ⁽⁵⁾	(5,133)	(3,814)
Distributable Cash Flow	\$ 60,835	\$ 43,475

(1) Represents Anadarko Petroleum Corporation's (Anadarko (NYSE: APC)) non-controlling interest in the operating results of Atlas Pipeline Mid-Continent WestOk, LLC (WestOK) and Atlas Pipeline Mid-Continent WestTex, LLC (WestTX); and MarkWest Oklahoma Gas Company, LLC's, (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE) non-controlling interest in Centrahoma Processing, LLC (Centrahoma).

(2) Represents the depreciation, amortization and interest expense included in income attributable to non-controlling interest for MarkWest's interest in Centrahoma.

(3) Represents the non-cash impact of commodity price movements on pipeline linefill.

- (4) Represents minimum volume adjustments on certain producer throughput contracts.
- (5) Net of non-controlling interest maintenance capital of \$192 thousand and \$41 thousand for the three months ended March 31, 2014 and 2013, respectively.

Table of Contents**Results of Operations**

The following table illustrates selected pricing before the effect of derivatives and volumetric information for the periods indicated:

	Three Months Ended March 31,		Percent Change
	2014	2013	
Pricing:			
Weighted Average Market Prices:			
NGL price per gallon Conway hub	\$ 1.00	\$ 0.83	20.5%
NGL price per gallon Mt. Belvieu hub	0.97	0.85	14.1%
Natural gas sales (\$/Mcf):			
SouthOK	4.78	3.17	50.8%
WestOK	4.76	3.20	48.8%
WestTX	4.73	3.12	51.6%
Weighted Average	4.75	3.17	49.8%
NGL sales (\$/gallon):			
SouthOK	1.06	0.72	47.2%
SouthTX	1.05		
WestOK	1.19	0.98	21.4%
WestTX	0.99	0.93	6.5%
Weighted Average	1.07	0.84	27.4%
Condensate sales (\$/barrel):			
SouthOK	90.41	91.86	(1.6)%
SouthTX	85.92		
WestOK	85.32	83.67	2.0%
WestTX	98.65	88.02	12.1%
Weighted Average	89.05	86.00	3.5%

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	Three Months Ended March 31,		Percent Change
	2014	2013	
Operating data:			
SouthOK:			
Gathered gas volume (MCFD)	399,700	391,499	2.1%
Processed gas volume (MCFD)	372,653	326,678	14.1%
Residue gas volume (MCFD)	335,397	310,082	8.2%
NGL volume (BPD)	28,270	34,552	(18.2)%
Condensate volume (BPD)	803	563	42.6%
SouthTX system:			
Gathered gas volume (MCFD)	96,333		100.0%
Processed gas volume (MCFD)	93,760		100.0%
Residue gas volume (MCFD)	74,913		100.0%
NGL volume (BPD)	11,870		100.0%
Condensate volume (BPD)	147		100.0%
WestOK system:			
Gathered gas volume (MCFD)	531,647	452,368	17.5%
Processed gas volume (MCFD)	510,160	425,431	19.9%
Residue gas volume (MCFD)	467,269	396,694	17.8%
NGL volume (BPD)	23,010	16,251	41.6%
Condensate volume (BPD)	2,164	1,969	9.9%
WestTX system ⁽¹⁾ :			
Gathered gas volume (MCFD)	408,531	312,571	30.7%
Processed gas volume (MCFD)	390,014	280,756	38.9%
Residue gas volume (MCFD)	286,934	209,891	36.7%
NGL volume (BPD)	50,263	33,245	51.2%
Condensate volume (BPD)	1,192	1,033	15.4%
Barnett system:			
Average throughput volumes (MCFD)	19,900	21,401	(7.0)%
Tennessee system:			
Average throughput volumes (MCFD)	8,941	9,495	(5.8)%
WTLPG system ⁽¹⁾ :			
Average NGL volumes (BPD)	248,623	244,626	1.6%

- (1) Operating data for SouthOK, WestTX and WTLPG represent 100% of operating activity for these systems. SouthOK gathered volumes include volumes gathered by MarkWest and processed through the Arkoma facilities.

Table of Contents*Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013*

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2014 and 2013 (in thousands):

	Three Months Ended March 31,			
	2014	2013	Variance	Percent Change
<i>Gross margin</i> ⁽¹⁾				
Natural gas and liquids sales	\$ 663,130	\$ 383,848	\$ 279,282	72.8%
Transportation, processing and other fees	43,437	32,725	10,712	32.7%
Less: non-cash line fill gain (loss) ⁽²⁾	143	(32)	175	546.9%
Less: natural gas and liquids cost of sales	575,468	325,540	249,928	76.8%
Gross margin	130,956	91,065	39,891	43.8%
Gross margin %	19.7%	23.7%		
<i>Expenses:</i>				
Operating expenses	25,128	21,859	3,269	15.0%
General and administrative ⁽³⁾	17,940	13,798	4,142	30.0%
Other costs	37	530	(493)	(93.0)%
Depreciation and amortization	49,239	30,458	18,781	61.7%
Interest expense	23,663	18,686	4,977	26.6%
Total expenses	116,007	85,331	30,676	35.9%
<i>Other income items:</i>				
Derivative loss, net	(8,671)	(12,083)	3,412	28.2%
Other income, net	2,108	3,422	(1,314)	(38.4)%
Non-cash line fill gain (loss) ⁽²⁾	143	(32)	175	546.9%
Equity income (loss) in joint ventures	(1,878)	2,040	(3,918)	(192.1)%
Loss on early extinguishment of debt		(26,582)	26,582	(100.0)%
Income tax benefit	398	9	389	4,322.2%
Income attributable to non-controlling interests ⁽⁴⁾	(2,462)	(1,369)	(1,093)	(79.8)%
Preferred unit imputed dividend effect	(11,378)		(11,378)	(100.0)%
Preferred unit dividends in kind	(9,719)		(9,719)	(100.0)%
Preferred unit dividends	(406)		(406)	(100.0)%
Net loss attributable to common limited partners and General Partner	\$ (16,916)	\$ (28,861)	\$ 11,945	41.4%
<i>Non-GAAP financial data:</i>				
EBITDA ⁽¹⁾	\$ 79,553	\$ 21,643	\$ 57,910	267.6%
Adjusted EBITDA ⁽¹⁾	90,804	67,706	23,098	34.1%
Distributable cash flow ⁽¹⁾	60,835	43,475	17,360	39.9%

(1)

Gross margin, EBITDA, Adjusted EBITDA and distributable cash flow are non-GAAP financial measures (see [How We Evaluate Our Operations](#) and [Non-GAAP Financial Measures](#)).

- (2) Includes the non-cash impact of commodity price movements on pipeline linefill.
- (3) General and administrative also includes compensation reimbursement to affiliates.
- (4) Represents Anadarko's non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest's non-controlling interest in Centrahoma.

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Gross margin

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the three months ended March 31, 2014 increased primarily due to higher production volumes. Overall gross margin percentages are lower for the three months ended March 31, 2014 due to the increase in natural gas prices, which increased at a higher rate than NGL prices, negatively impacting the gross margin rate achieved on Keep-Whole contracts.

Volumes on the SouthOK system for the three months ended March 31, 2014 increased from the prior year period volumes primarily due to increased volumes from XTO Energy, Inc., which were processed through the V60 plant which commenced operation during the third quarter of the prior year.

New volumes from the SouthTX system are due to the TEAK Acquisition in May 2013 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Acquisitions).

Volumes on the WestOK system increased for the three months ended March 31, 2014 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand.

WestTX system gathering and processing volumes for the three months ended March 31, 2014 increased compared to the prior year period due to continued increased volumes from Pioneer Natural Resources Company (NYSE: PXD) and others as a result of their continued drilling programs, and the start-up of the Driver plant in April 2013.

Transportation, processing and other fees for the three months ended March 31, 2014 increased primarily due to \$7.4 million in additional fee-based revenues on the SouthTX system acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Acquisitions) and increased processing fee revenue of \$1.5 million on the WestOK system related to the increased volumes gathered on the systems.

Expenses

Operating expenses, comprised primarily of plant operating expenses and transportation and compression expenses, for the three months ended March 31, 2014 increased mainly due to \$3.1 million in additional expenses from the SouthTX systems acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Acquisitions) and a \$1.4 million increase on the WestTX system primarily due to increased gathered volumes.

General and administrative expense, including amounts reimbursed to affiliates, increased for the three months ended March 31, 2014 mainly due to a \$2.1 million increase in share-based compensation related to phantom units granted to employees (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 15 Benefit Plans) and a \$2.1 million increase in salaries and wages partially due to the increase in the number of employees as a result of the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Acquisitions).

Other costs for the three months ended March 31, 2014 decreased mainly due to acquisition costs related to the certain assets we acquired from Cardinal Midstream, LLC in December 2012 recorded in the prior year period.

Depreciation and amortization expense for the three months ended March 31, 2014 increased primarily due to \$11.6 million additional expense related to assets acquired in the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Acquisitions) and due to growth capital expenditures incurred subsequent to March 31, 2013.

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Interest expense for the three months ended March 31, 2014 increased primarily due to \$4.8 million additional interest related to the 4.75% unsecured senior notes due November 15, 2012 (4.75% Senior Notes) and \$4.2 million additional interest related to the 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes), offset by \$4.2 million reduced interest expense on the 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes). The increase in the interest on the 4.75% Senior Notes and the 5.875% Senior Notes is due to their issuance in 2013 (see Senior Notes). The decrease in the interest for the 8.75% Senior Notes is due to their redemption in February 2013 (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 13 Debt 8.75% Senior Notes).

Other income items

Derivative loss, net for the three months ended March 31, 2014 had a \$14.9 million favorable variance compared to the prior year period primarily due to an increase in forward prices during the prior year period resulting in mark-to-market losses on derivatives, offset by \$11.5 million unfavorable cash settlements in the current year period compared to the prior year period. While we utilize either quoted market prices or observable market data to calculate the fair value of natural gas and crude oil derivatives, valuations of NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGLs for similar geographic locations, and valuations of NGL options are based on forward price curves developed by third-party financial institutions. The use of unobservable market data for NGL fixed price swaps and NGL options has no impact on the settlement of these derivatives. However, a change in management's estimated fair values for these derivatives could impact net income, although it would have no impact on liquidity or capital resources (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 10 Derivative Instruments for further discussion of derivative instrument valuations). We recognized a \$1.1 million and \$2.4 million mark-to-market loss on derivatives that were valued based upon unobservable inputs for the three months ended March 31, 2014 and 2013, respectively. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3: Quantitative and Qualitative Disclosures About Market Risk.

Other income, net for the three months ended March 31, 2014 had an unfavorable variance primarily due to a \$1.0 million settlement of business interruption insurance related to a loss of revenue in our WestOK system in May 2011 due to storm damage at the Chester plant, which was settled during the prior year period.

Non-cash line fill loss had a favorable variance for the three months ended March 31, 2014 compared to the prior year period primarily due to a gain on additional linefill volumes at SouthTX that are valued at mark-to-market due to an increase in the forward price curve.

Equity income (loss) in joint ventures decreased for the three months ended March 31, 2014 primarily due to a \$3.6 million loss in the current period from the SouthTX equity method investments. The T2 LaSalle and T2 Eagle Ford joint ventures are structured to earn revenues equal to their operating costs, exclusive of depreciation expense. The loss primarily represents depreciation expense.

Loss on early extinguishment of debt for the three months ended March 31, 2013 represents \$17.5 million premiums paid; \$8.0 million consent payment made; and \$5.3 million write off of deferred financing costs, offset by \$4.2 million recognition of unamortized premium related to the redemption of the 8.75% Senior Notes (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 13 Debt 8.75% Senior Notes).

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Income tax benefit for the three months ended March 31, 2014 represents the accrued income tax related to the income earned on APL Arkoma, Inc. The favorable variance compared to the prior period is due to APL Arkoma, Inc. incurring a larger taxable loss compared to the prior period.

Income attributable to non-controlling interests increased primarily due to Anadarko's non-controlling interest in higher net income for the WestOK and WestTX joint ventures. The increase in net income of the WestOK and WestTX joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher volumes.

Preferred unit imputed dividend effect for the current period represents the accretion of the beneficial conversion discount of the Class D Preferred Units (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 5 Equity).

Preferred unit dividends in-kind for the current period represent the distributions to the Class D Preferred Units, which have been declared (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 5 Equity).

Preferred unit dividends for the current period represent the distributions to the Class E Preferred Units, attributable to the three month period ended March 31, 2014 (see Class E Preferred Units).

Non-GAAP financial data

Adjusted EBITDA had a favorable variance for the three months ended March 31, 2014 compared to the prior year period mainly due to the improved gross margin variance, as discussed above in Gross Margin, partially offset by higher operating expenses and general and administrative expenses as discussed above in Expenses.

Distributable cash flow had a favorable variance for the three months ended March 31, 2014 compared to the prior year period mainly due to the favorable Adjusted EBITDA variance, as discussed above, partially offset by higher interest expense as discussed above in Expenses and higher maintenance capital expenditures (see further discussion of capital expenditures under Capital Requirements).

Liquidity and Capital Resources*General*

At March 31, 2014, we had \$150.0 million outstanding borrowings under our \$600.0 million senior secured revolving credit facility and \$0.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with \$449.9 million of remaining committed capacity under the revolving credit facility, (see Revolving Credit Facility). We were in compliance with the credit facility's covenants at March 31, 2014. We had a working capital deficit of \$78.1 million at March 31, 2014 compared with a \$78.4 million working capital deficit at December 31, 2013. We believe 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 flows. We may need to supplement our cash generation with proceeds from financing activities, including borrowings under our revolving credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

Table of Contents*Cash Flows Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013*

The following table details the cash flow changes between the three months ended March 31, 2014 and 2013 (in thousands):

	Three Months Ended March 31,			Percent Change
	2014	2013	Variance	
Net cash provided by (used in):				
Operating activities	\$ 66,168	\$ 41,256	\$ 24,912	60.4%
Investing activities	(130,684)	(108,390)	(22,294)	(20.6)%
Financing activities	69,358	71,997	(2,639)	(3.7)%
Net change in cash and cash equivalents	\$ 4,842	\$ 4,863	\$ (21)	

Net cash provided by operating activities for the three months ended March 31, 2014 increased compared to the prior year period primarily due to a \$21.5 million increase in net earnings from continuing operations excluding non-cash charges. The increase is primarily due to increased gross margins from the sale of natural gas and NGLs offset by an increase in operating expense, general and administrative expense and interest expense (see Results of Operations).

Net cash used in investing activities for the three months ended March 31, 2014 increased compared to the prior year period mainly due to a \$19.8 million increase in capital expenditures in the current year period compared to the prior year period (see further discussion of capital expenditures under Capital Requirements).

Net cash provided by financing activities for the three months ended March 31, 2014 decreased compared to the prior year period mainly due to (i) \$637.1 million provided by the issuance of the 5.875% Senior Notes in the prior year period, (ii) a \$15.8 million increase in distributions paid in the current period compared to the prior year period and (iii) \$14.1 million provided by the issuance of common units in the prior year period under our equity distribution program. These decreases were partially offset by (i) the \$391.4 million redemption of the 8.75% Senior Notes, including the cost of early retirement of debt in the prior year period; (ii) a \$136.5 million, net decrease in the prior year period to outstanding borrowings on the revolving credit facility; and (iii) \$122.4 million provided by the issuance of the Class E Preferred Units in the current period (see Class E Preferreds). The gross amount of borrowings and repayments under the revolving credit facility included within net cash provided by (used in) financing activities in the consolidated combined statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of (i) cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under the revolving credit facility, and (ii) payments, which generally occur throughout the period and increase borrowings under the revolving credit facility, which is generally common practice for the industry.

Table of Contents**Capital Requirements**

Our operations require continual investment to upgrade or enhance existing operations and to ensure compliance with safety, operational, and environmental regulations. Our capital requirements consist primarily of:

maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and

expansion capital expenditures to acquire complementary assets and to expand the capacity of our existing operations.

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

	Three Months Ended	
	March 31,	
	2014	2013
Maintenance capital expenditures	\$ 5,325	\$ 3,855
Expansion capital expenditures	123,006	104,661
Total	\$ 128,331	\$ 108,516

The increase in maintenance capital expenditures for the three months ended March 31, 2014 when compared with the prior year period was due to fluctuations in the timing of scheduled maintenance activity.

Expansion capital expenditures increased for the three months ended March 31, 2014 primarily due to construction costs for the Stonewall Plant within SouthOK scheduled to be placed in service during second quarter of 2014, the Silver Oak II Plant within SouthTX scheduled to be placed in service during the second quarter of 2014, the Edward Plant within WestTX scheduled to be placed in service in late 2014 and the construction of the Velma to Arkoma connection within SouthOK scheduled to be completed during third quarter 2014. As of March 31, 2014, we had approved additional expenditures of approximately \$427.8 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately \$74.0 million in purchase commitments had been made. We expect to fund these projects through operating cash flows and borrowings under our revolving credit facility.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash, for each calendar quarter, to our common unitholders and our General Partner within 45 days following the end of such calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance in May 2013, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of our General Partner.

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Our General Partner is granted discretion by our 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. When our General Partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2.0% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 2.0% of the aggregate amount of cash being distributed. Our General Partner, holder of all our incentive distribution rights, has agreed to allocate up to \$3.75 million of its incentive distribution rights per quarter back to us after the General Partner receives the initial \$7.0 million of incentive distribution rights per quarter. Incentive distributions of \$5.0 million and \$2.3 million were paid during the three months ended March 31, 2014 and 2013, respectively.

Off Balance Sheet Arrangements

As of March 31, 2014, our off balance sheet arrangements include our letters of credit, issued under the provisions of our revolving credit facility, totaling \$0.1 million. These are in place to support various performance obligations as required by (1) statutes within the regulatory jurisdictions where we operate, (2) surety and (3) counterparty support.

We have certain long-term unconditional purchase obligations and commitments, primarily throughput contracts. These agreements provide transportation services to be used in the ordinary course of our operations.

Class E Preferred Units

On March 17, 2014, we issued 5,060,000 of our Class E Preferred Units to the public at an offering price of \$25.00 per Class E Preferred Unit. We received \$122.4 million in net proceeds, which were used to pay down the revolving credit facility. We will make cumulative cash distributions on the Class E Preferred Units from the date of original issue. The cash distributions will be payable quarterly in arrears on January 15, April 15, July 15, and October 15 of each year, when, and if, declared by the board of directors. The initial distribution on the Class E Preferred Units will be payable on July 15, 2014 in an amount equal to \$0.67604 per unit, or approximately \$3.4 million. Thereafter, we will pay cumulative distributions in cash on the Class E Preferred Units on a quarterly basis at a rate of \$0.515625 per unit, or 8.25% per year (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Equity).

Revolving Credit Facility

At March 31, 2014, we had a \$600.0 million senior secured revolving credit facility with a syndicate of banks, which matures in May 2017. The weighted average interest rate for borrowings on the revolving credit facility, at March 31, 2014, was 3.2%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$0.1 million was outstanding at March 31, 2014. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

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On March 11, 2014, we entered into an amendment to the credit agreement governing our revolving credit facility, which among other changes, adjusted the Acquisition Period for the Consolidated Funded Debt Ratio, and permitted the payment of cash distributions on the Class E Preferred Units (see [Class E Preferred Units](#)).

The events that constitute an event of default for our revolving credit facility include payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. As of March 31, 2014, we were in compliance with all covenants under the revolving credit facility.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP 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 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 subject to such estimates and assumptions include revenue and expense accruals, 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.

There have been no material changes in the methodology applied by management for critical accounting policies and estimates from those disclosed in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2013.

Recently Adopted Accounting Standards

See [Item 1: Notes to Consolidated Financial Statements \(Unaudited\)](#) [Note 2](#) [Recently Adopted Accounting Standards](#) for information regarding recently adopted accounting pronouncements.

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 oil and natural gas 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 our market risk sensitive instruments were entered into for purposes other than trading.

General

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 instruments.

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The information about commodity price risk and interest rate risk for the three months ended March 31, 2014 does not differ materially from that discussed in Item 7A. Quantitative and Qualitative Disclosures about Market Risk of our Annual Report on Form 10-K for the year ended December 31, 2013.

ITEM 4. CONTROLS AND PROCEDURES

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

Under the supervision of our General Partner's Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner's Chief Executive Officer and Chief Financial Officer concluded that, as of March 31, 2014, our disclosure controls and procedures were effective at the reasonable assurance level.

There have been no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents**PART II. OTHER INFORMATION****ITEM 1A. RISK FACTORS**

There have been no material changes in our risk factors from those disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2013.

ITEM 6. EXHIBITS

Exhibit No.	Description
1.1	Underwriting Agreement, dated March 12, 2014, among Atlas Pipeline Partners, L.P. and the underwriters named therein ⁽³⁶⁾
2.1	Purchase and Sale agreement, dated as of April 16, 2013, among TEAK Midstream Holdings, LLC, TEAK Midstream, L.L.C. and Atlas Pipeline Mid-Continent Holdings, LLC. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request ⁽³³⁾
3.1(a)	Certificate of Limited Partnership ⁽¹⁾
3.1(b)	Amendment to Certificate of Limited Partnership ⁽¹²⁾
3.2(a)	Second Amended and Restated Agreement of Limited Partnership ⁽²⁾
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership ⁽³⁾
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership ⁽⁴⁾
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership ⁽⁵⁾
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership ⁽⁶⁾
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership ⁽⁸⁾
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership ⁽⁹⁾
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership ⁽¹⁴⁾
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership ⁽¹⁵⁾
3.2(j)	Amendment No. 9 to Second Amended and Restated Agreement of Limited Partnership ⁽¹²⁾
3.2(k)	Amendment No. 10 to Second Amended and Restated Agreement of Limited Partnership ⁽³⁰⁾
3.2(j)	Amendment No. 11 to Second Amended and Restated Agreement of Limited Partnership ⁽³⁶⁾
4.1	Common unit certificate (attached as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership) ⁽²⁾
4.2(a)	6 5/8% Senior Notes Indenture dated September 28, 2012 ⁽²⁶⁾

- 4.2(b) Supplemental Indenture dated as of December 20, 2012⁽³²⁾
- 4.3(a) 5 7/8% Senior Notes Indenture dated as of February 11, 2013⁽¹⁰⁾
- 4.3(b) Supplemental Indenture dated as of February 11, 2013⁽¹⁰⁾
- 4.4 4 3/4% Senior Notes Indenture dated May 10, 2013⁽⁷⁾
- 4.5(a) Certificate of Designation of Class D Convertible Preferred Units⁽³⁰⁾
- 4.5(b) Certificate of Amendment to Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional, and Other Special Rights and Qualifications, Limitations and Restrictions Thereof, dated as of March 12, 2014⁽³⁶⁾
- 4.6 Registration Rights Agreement, dated May 16, 2012, between Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein⁽²⁵⁾
- 4.7 Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional, and Other Special Rights of Preferred Units and Qualifications, Limitations and Restrictions Thereof, dated as of March 17, 2014⁽³⁶⁾

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Exhibit No.	Description
10.1(a)	Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽¹⁾
10.1(b)	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽¹⁴⁾
10.1(c)	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽¹²⁾
10.1(d)	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. ⁽³⁶⁾
10.2	Second Amended and Restated Limited Liability Company Agreement of Atlas Pipeline Partners GP, LLC. ⁽¹⁹⁾
10.3(a)	Amended and Restated Credit Agreement dated July 27, 2007, amended and restated as of December 22, 2010, by and among Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the several guarantors and lenders hereto ⁽¹⁶⁾
10.3(b)	Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011 ⁽²²⁾
10.3(c)	Incremental Joinder Agreement to the Amended and Restated Credit Agreement dated as of July 8, 2011 ⁽²³⁾
10.3(d)	Amendment No. 2 to the Amended and Restated Credit Agreement dated as of May 31, 2012 ⁽²⁷⁾
10.3(e)	Amendment No. 3 to the Amended and Restated Credit Agreement ⁽³¹⁾
10.3(f)	Amendment No. 4 to the Amended and Restated Credit Agreement ⁽³⁴⁾
10.3(g)	Amendment No. 6 to the Amended and Restated Credit Agreement ⁽³⁷⁾
10.4	Long-Term Incentive Plan ⁽³⁵⁾
10.5	Amended and Restated 2010 Long-Term Incentive Plan ⁽²²⁾
10.6	Form of Grant of Phantom Units in Exchange for Bonus Units ⁽¹⁷⁾
10.7	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter ⁽¹⁸⁾
10.8	Form of 2004 Long-Term Incentive Plan Phantom Unit Grant Letter ⁽²⁸⁾
10.9	Form of Grant of Phantom Units to Non-Employee Managers ⁽¹¹⁾
10.10	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010 ⁽¹³⁾
10.11	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010 ⁽²⁰⁾
10.12	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010 ⁽²⁰⁾
10.13	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011 ⁽²⁴⁾
10.14	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011 ⁽²⁴⁾

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- 10.15 Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011⁽²¹⁾
- 10.16 Employment Agreement between Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Patrick J. McDonie dated as of July 3, 2012⁽²⁵⁾
- 10.17 Equity Distribution Agreement dated November 5, 2012, by and between Atlas Pipeline Partners, L.P. and Citigroup Global Markets Inc.⁽²⁹⁾
- 10.18 Class D Preferred Unit Purchase Agreement, dated as of April 17, 2013, among Atlas Pipeline Partners, L.P. and the various purchasers party thereto⁽³³⁾
- 10.19 Registration Rights Agreement, dated February 11, 2013, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein ⁽¹⁰⁾

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Exhibit No.	Description
10.20	Purchase Agreement dated January 28, 2013 by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries listed therein, and Merrill Lynch, Pierce, Fenner & Smith Incorporated as representative of the several initial purchasers ⁽²⁶⁾
10.21	Registration Rights Agreement, dated May 7, 2013 by and among Atlas Pipeline Partners, L.P. and the purchasers named therein ⁽³⁰⁾
10.22	Registration Rights Agreement, dated May 10, 2013, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the guarantors named therein, and Citigroup Global Markets Inc. for itself and on behalf of the initial purchasers ⁽⁷⁾
10.23	Purchase Agreement dated May 7, 2013 among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, and Citigroup Global Markets Inc. as representatives of the several initial purchasers ⁽⁷⁾
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification
101.INS	XBRL Instance Document ⁽³⁸⁾
101.SCH	XBRL Schema Document ⁽³⁸⁾
101.CAL	XBRL Calculation Linkbase Document ⁽³⁸⁾
101.LAB	XBRL Label Linkbase Document ⁽³⁸⁾
101.PRE	XBRL Presentation Linkbase Document ⁽³⁸⁾
101.DEF	XBRL Definition Linkbase Document ⁽³⁸⁾

- (1) Filed previously as an exhibit to registration statement on Form S-1 (Registration No. 333-85193).
- (2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
- (3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
- (4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
- (5) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
- (6) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
- (7) Previously filed as an exhibit to current report on Form 8-K on May 13, 2013.
- (8) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
- (9) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
- (10) Previously filed as an exhibit to current report on Form 8-K filed on February 12, 2013.
- (11) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2010.
- (12) Previously filed as an exhibit to current report on Form 8-K on December 13, 2011.
- (13) Previously filed as an exhibit to current report on Form 8-K on November 12, 2010.
- (14) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
- (15) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
- (16) Previously filed as an exhibit to current report on Form 8-K on December 23, 2010.

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- (17) Previously filed as an exhibit to current report on Form 8-K filed on June 17, 2010.
- (18) Previously filed as an exhibit to current report on Form 8-K filed on June 23, 2010.
- (19) Previously filed as an exhibit to current report on Form 8-K on October 29, 2013.
- (20) Previously filed as an exhibit to Atlas Energy, Inc. s current report on Form 8-K filed on November 12, 2010.
- (21) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2011.
- (22) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2011.
- (23) Previously filed as an exhibit to current report on Form 8-K filed on July 11, 2011.
- (24) Previously filed as an exhibit to Atlas Energy, L.P. s quarterly report on Form 10-Q for the quarter ended March 31, 2011.
- (25) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2012.
- (26) Previously filed as an exhibit to current report on Form 8-K filed on January 30, 2013.
- (27) Previously filed as an exhibit to current report on Form 8-K filed on May 31, 2012.
- (28) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2012.

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- (29) Previously filed as an exhibit to current report on Form 8-K filed on November 6, 2012.
- (30) Previously filed as an exhibit to current report on Form 8-K filed on May 8, 2013.
- (31) Previously filed as an exhibit to current report on Form 8-K filed on December 13, 2012.
- (32) Previously filed as an exhibit to current report on Form 8-K filed on December 26, 2012.
- (33) Previously filed as an exhibit to current report on Form 8-K filed on April 17, 2013.
- (34) Previously filed as an exhibit to current report on Form 8-K filed on April 23, 2013.
- (35) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2009.
- (36) Previously filed as an exhibit to current report on Form 8-K filed on March 17, 2014.
- (37) Previously filed as an exhibit to current report on Form 8-K filed on March 11, 2014.
- (38) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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SIGNATURES

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

ATLAS PIPELINE PARTNERS, L.P.

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

Date: May 8, 2014

By: /s/ EUGENE N. DUBAY
Eugene N. Dubay
Chief Executive Officer, President and
Managing Board Member of the General Partner

Date: May 8, 2014

By: /s/ ROBERT W. KARLOVICH, III
Robert W. Karlovich, III
Chief Financial Officer and Chief Accounting
Officer of the General Partner