ATLAS PIPELINE PARTNERS LP
Form 10-Q
May 06, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2013

OR

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

For the transition period from _________ to _________

Commission file number:1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
Park Place Corporate Center One 1000 Commerce Drive, 4th Floor Pittsburgh, Pennsylvania	**15275-1011**
(Address of principal executive office)	**(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 x No ¨

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

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

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

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

The number of common units of the registrant outstanding on May 2, 2013 was 76,918,206.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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ON FORM 10-Q

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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 considered to be a non-GAAP measurement.
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
GPM	Gallons per minute
Keep-Whole	Contract with producer whereby 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)	Contract with natural gas producers 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.
SEC	Securities and Exchange Commission

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	March 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 8,261	$ 3,398
Funds held in escrow	25,001	25,000
Accounts receivable	162,556	157,526
Current portion of derivative assets	17,391	23,077
Prepaid expenses and other	11,905	11,074
Total current assets	225,114	220,075
Property, plant and equipment, net	2,299,967	2,200,381
Goodwill	319,285	319,285
Intangible assets, net	182,786	199,360
Equity method investment in joint venture	86,242	86,002
Long-term portion of derivative assets	2,378	7,942
Other assets, net	38,658	32,593
Total assets	$ 3,154,430	$ 3,065,638
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 8,861	$ 10,835
Accounts payable affiliates	4,338	5,500
Accounts payable	71,703	59,308
Accrued liabilities	47,007	57,752
Accrued interest payable	5,474	10,399
Current portion of derivative liability	619	
Accrued producer liabilities	114,057	109,725
Total current liabilities	252,059	253,519
Long-term portion of derivative liability	925	
Long-term debt, less current portion	1,310,051	1,169,083
Deferred income taxes, net	30,249	30,258
Other long-term liability	6,358	6,370
Commitments and contingencies		
Equity:		
Common limited partners interests	1,456,911	1,507,676
General Partner s interest	31,031	31,501

Total partners capital	1,487,942	1,539,177
Non-controlling interest	66,846	67,231
Total equity	1,554,788	1,606,408
Total liabilities and equity	$ 3,154,430	$ 3,065,638

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, 2013	Three Months Ended March 31, 2012
Revenue:		
Natural gas and liquids sales	$ 383,848	$ 289,225
Transportation, processing and other fees third parties	32,654	12,602
Transportation, processing and other fees affiliates	71	79
Derivative loss, net	(12,083)	(12,035)
Other income, net	3,422	2,415
Total revenues	407,912	292,286
Costs and expenses:		
Natural gas and liquids cost of sales	325,540	233,105
Plant operating	21,271	13,881
Transportation and compression	588	264
General and administrative	12,548	9,070
Compensation reimbursement affiliates	1,250	875
Other costs	530	(34)
Depreciation and amortization	30,458	20,842
Interest	18,686	8,708
Total costs and expenses	410,871	286,711
Equity income in joint venture	2,040	896
Loss on early extinguishment of debt	(26,582)	
Income (loss) before tax	(27,501)	6,471
Income tax benefit	(9)	
Net income (loss)	(27,492)	6,471
Income attributable to non-controlling interests	(1,369)	(1,536)
Net income (loss) attributable to common limited partners and the General Partner	$ (28,861)	$ 4,935
Allocation of net income (loss) attributable to:		
Common limited partner interest	$ (31,206)	$ 3,467
General Partner interest	2,345	1,468
	$ (28,861)	$ 4,935
Net income (loss) attributable to common limited partners per unit:		
Basic	$ (0.48)	$ 0.06
Weighted average common limited partner units (basic)	64,646	53,620

Diluted	$ (0.48)	$ 0.06
Weighted average common limited partner units (diluted)	64,646	54,013

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

(Unaudited)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Net income (loss)	$ (27,492)	$ 6,471
Income attributable to non-controlling interests	(1,369)	(1,536)
Net income (loss) attributable to common limited partners and the General Partner	(28,861)	4,935
Other comprehensive income:		
Adjustment for realized losses on cash flow commodity based derivatives reclassified to net income		1,146
Comprehensive income (loss)	$ (28,861)	$ 6,081

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY

FOR THE THREE MONTHS ENDED MARCH 31, 2013

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Common Units	Common Limited Partners	General Partner	Non-controlling Interest	Total
Balance at December 31, 2012	64,556,010	$ 1,507,676	$ 31,501	$ 67,231	$ 1,606,408
Issuance of units and General Partner capital contribution	447,785	14,144	302		14,446
Issuance of common units under incentive plans	1,911	63			63
Unissued common units under incentive plans		4,287			4,287
Distributions paid		(38,053)	(3,117)		(41,170)
Distributions received from non-controlling interests				26	26
Decrease in non-controlling interest due to business combination				(1,780)	(1,780)
Net income (loss)		(31,206)	2,345	1,369	(27,492)
Balance at March 31, 2013	65,005,706	$ 1,456,911	$ 31,031	$ 66,846	$ 1,554,788

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (27,492)	$ 6,471
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	30,458	20,842
Equity income in joint venture	(2,040)	(896)
Distributions received from equity method joint venture	1,800	1,800
Non-cash compensation expense	4,384	978
Amortization of deferred finance costs	1,544	1,165
Loss on early extinguishment of debt	26,582	
Deferred income tax benefit	(9)	
Change in operating assets and liabilities, net of business combinations:		
Accounts receivable, prepaid expenses and other	(7,211)	13,589
Accounts payable and accrued liabilities	(4,392)	(16,075)
Accounts payable and accounts receivable affiliates	(1,162)	426
Derivative accounts payable and receivable	12,794	14,447
Net cash provided by operating activities	35,256	42,747
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(108,516)	(81,167)
Cash paid for business combinations, net of cash received		(17,235)
Other	126	126
Net cash used in investing activities	(108,390)	(98,276)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	278,000	319,500
Repayments under credit facility	(416,500)	(231,500)
Net proceeds from issuance of long term debt	637,090	
Repayment of debt	(365,822)	
Payment of premium on retirement of debt	(25,562)	
Payment of deferred financing costs	(99)	(33)
Principal payments on capital lease	(2,135)	(539)
Net proceeds from issuance of common limited partner units	14,144	
General Partner capital contributions	302	
Net distributions received from non-controlling interest holders	26	38
Distributions paid to common limited partners and the General Partner	(41,170)	(31,737)
Other	(277)	(200)
Net cash provided by financing activities	77,997	55,529
Net change in cash and cash equivalents	4,863	

Cash and cash equivalents, beginning of period		3,398		168
Cash and cash equivalents, end of period	$	8,261	$	168

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, 2013

(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 wholly-owned subsidiary of the Partnership. At March 31, 2013, 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, 2013, the Partnership had 65,005,706 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS.

The accompanying consolidated financial statements, which are unaudited, except the balance sheet at December 31, 2012, 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. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management s opinion, all adjustments necessary for a fair presentation of the Partnership s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2012. The results of operations for the three month period ended March 31, 2013 may not necessarily be indicative of the results of operations for the full year ending December 31, 2013.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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, 2012.

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. These changes, other than net income (loss), are referred to as other comprehensive income (loss) and for the Partnership only include changes in the fair value of unsettled derivative contracts which were previously accounted for as cash flow hedges (see Note 9). During the three months ended March 31, 2012, the Partnership reclassified $1.1 million from other comprehensive income to natural gas and liquids sales within the Partnership s consolidated statements of operations. As of January 1, 2013, all amounts had been reclassified out of other comprehensive income and the Partnership had no amounts outstanding within other comprehensive income.

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Equity Method Investments

The Partnership s consolidated financial statements include its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG). The Partnership accounts for its investment in the joint ventures under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint ventures net income as equity income on its consolidated statements of operations. Investments in excess of the underlying net assets of equity method investees identifiable to property, plant and equipment or finite lived intangible assets are amortized over the useful life of the related assets and recorded as a reduction to equity investment on the Partnership s consolidated balance sheet with an offsetting reduction to equity income on the Partnership s consolidated statements of operations. Excess investment representing equity method goodwill is not amortized but is evaluated for impairment, annually. This goodwill is not subject to amortization and is accounted for as a component of the investment. No goodwill was recorded on the acquisition of WTLPG. The Partnership had $86.2 million and $86.0 million equity method investment in WTLPG at March 31, 2013 and December 31, 2012, respectively, which was included with equity method investment in joint venture on its consolidated balance sheets. The Partnership recorded equity income in joint venture of $2.0 million and $0.9 million on its consolidated statements of operations for the three months ended March 31, 2013 and March 31, 2012, respectively, related to its interest in WTLPG.

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% general partner interest and incentive distributions to be distributed for the quarter (see Note 4), 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 14), 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.

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, 2013	Three Months Ended March 31, 2012
Net income (loss)	$ (27,492)	$ 6,471
Income attributable to non-controlling interests	(1,369)	(1,536)
Net income (loss) attributable to common limited partners and the General Partner	(28,861)	4,935
General Partner s cash incentive distributions declared	2,986	1,397
General Partner s ownership interest	(641)	71
Net income attributable to the General Partner s ownership interests	2,345	1,468
Net income (loss) attributable to common limited partners	(31,206)	3,467
Net income attributable to participating securities phantom units(1)		25
Net income (loss) utilized in the calculation of net income (loss) attributable to common limited partners per unit	$ (31,206)	$ 3,442

(1) Net income 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, 2013, net loss attributable to common limited partners ownership interest is not allocated to approximately 1,055,000 phantom units, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, 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 unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership s long-term incentive plans (see Note 14).

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

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Weighted average number of common limited partner units basic	64,646	53,620
Add effect of participating securities phantom units(1)		393
Weighted average common limited partner units diluted	64,646	54,013

(1) For the three months ended March 31, 2013 approximately 1,055,000 phantom units 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.

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Revenue Recognition

The Partnership s revenue primarily consists of the sale of natural gas and NGLs along with the fees earned from its gathering, processing, treating and transportation operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced NGLs, if any, off delivery points on its systems. Under other agreements, the Partnership gathers natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas and NGLs is recognized upon physical delivery. In connection with the Partnership s gathering, processing and transportation operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas and for transporting NGLs. Revenue is a function of the volume of natural gas that the Partnership gathers and processes or the volume of NGLs transported and is not directly dependent on the value of the natural gas or NGLs. The Partnership is also paid a separate compression fee on many of its gathering systems. The fee is dependent upon the volume of gas flowing through its compressors and the quantity of compression stages utilized to gather the gas.

POP Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this contract-type, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership effectively owns a percentage of the commodity and revenues are directly correlated to its market value. POP contracts may include a fee component, which is charged to the producer.

Keep-Whole Contracts. These contracts require the Partnership, as the processor and gatherer, to gather or purchase raw natural gas at current market rates per MMBTU. The volume and energy content of gas gathered or purchased is based on the measurement at an agreed upon location (generally at the wellhead). The BTU quantity of gas redelivered or sold at the tailgate of the Partnership s processing facility may be lower than the BTU quantity purchased at the wellhead primarily due to the NGLs extracted from the natural gas when processed through a plant. The Partnership must make up or keep the producer whole for this loss in BTU quantity. To offset the make-up obligation, the Partnership retains the NGLs, which are extracted, and sells them for its own account. Therefore, the Partnership bears the economic risk (the processing margin risk) that (1) the BTU quantity of residue gas available for redelivery to the producer may be less than received from the producer; and/or (2) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under some Keep-Whole agreements are lower in BTU content and thus can meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods when the processing margin risk is uneconomic.

The Partnership accrues unbilled revenue 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, 2013 and December 31, 2012 of $87.3 million and $100.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

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Recently Adopted Accounting Standards

In February 2013, the FASB issued Accounting Standards Update (ASU) 2013-02, Other Comprehensive Income (Topic 220) Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, which, among other changes, requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component and the respective line items of net income to which the amounts were reclassified. The update does not change the components of comprehensive income that must be presented. These requirements are effective for interim and annual reporting periods beginning after December 15, 2012. The Partnership began including the additional required disclosures upon the adoption of this ASU on January 1, 2013 (see Comprehensive Income (Loss)). The adoption had no material impact on the Partnership s financial position or results of operations.

NOTE 3 ACQUISITIONS

On December 20, 2012, the Partnership completed the acquisition of 100% of the equity interests held by Cardinal Midstream, LLC (Cardinal) in three wholly-owned subsidiaries for $598.5 million in cash, including preliminary purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas. The acquisition includes a 60% interest in Centrahoma Processing, LLC (Centrahoma). The remaining 40% ownership interest is held by MarkWest Oklahoma Gas Company LLC (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. As of March 31, 2013, the accounting for the business combination has not been completed. The estimates of fair value reflected as of March 31, 2013 are subject to change and changes could be material. Revisions to these estimates will be recorded retrospectively during the measurement period of one year from the acquisition date of December 20, 2012.

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The following table presents the preliminary values assigned as of March 31, 2013 and December 31, 2012 to the assets acquired and liabilities assumed in the Cardinal Acquisition, based on their estimated fair values at the date of the acquisition, including the 40% non-controlling interest of Centrahoma held by MarkWest (in thousands):

	March 31, 2013	December 31, 2012
Cash	$ 3,246	$ 3,246
Accounts receivable	19,618	19,618
Prepaid expenses and other	1,377	1,377
Property, plant and equipment	295,855	295,855
Intangible assets contracts	107,530	107,530
Goodwill	310,904	310,904
Total assets acquired	738,530	738,530
Current portion of long-term debt	(341)	(341)
Accounts payable and accrued liabilities	(16,496)	(16,496)
Deferred tax liability, net	(30,082)	(30,082)
Long-term debt, less current portion	(604)	(604)
Total liabilities acquired	(47,523)	(47,523)
Non-controlling interest	(89,310)	(89,310)
Net assets acquired	**601,697**	**601,697**
Less cash received	(3,246)	(3,246)
Net cash paid for acquisition	**$ 598,451**	**$ 598,451**

The fair value of MarkWest s 40% non-controlling interest in Centrahoma was determined based upon the purchase price allocated to the 60% controlling interest the Partnership acquired.

NOTE 4 EQUITY

Common Units

The Partnership has an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, the Partnership may offer and sell from time to time through Citigroup, as its sales agent, common units having an aggregate value of up to $150.0 million. Subject to the terms and conditions of the equity distribution agreement, Citigroup will not be required to sell any specific number or dollar amount of the common units, but will use its reasonable efforts, consistent with its normal trading and sales practices, to sell such units. Such sales will be at market prices prevailing at the time of the sale. There will be no specific date on which the offering will end; there will be no minimum purchase requirements; and there will be no arrangements to place the proceeds of the offering in an escrow, trust or similar account. Under the terms of the equity distribution agreement, the Partnership also may sell common units to Citigroup as principal for its own account at a price agreed upon at the time of the sale. The Partnership intends to use the net proceeds from any such offering for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. 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.

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 and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General

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Partner will receive between 15% and 50% of such distributions in excess of the specified target levels, including the General Partner s 2% 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. Common unit and General Partner distributions declared by the Partnership for quarters ending from March 31, 2012 through December 31, 2012 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, 2012	May 15, 2012	$ 0.56	$ 30,030	$ 2,217
June 30, 2012	August 14, 2012	0.56	30,085	2,221
September 30, 2012	November 14, 2012	0.57	30,641	2,409
December 31, 2012	February 14, 2013	0.58	37,442	3,117

On April 24, 2013, the Partnership declared a cash distribution of $0.59 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2013. The $49.3 million distribution, including $4.0 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on May 15, 2013 to unitholders of record at the close of business on May 8, 2013.

NOTE 5 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 12) (in thousands):

	March 31, 2013	December 31, 2012	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 2,412,743	$ 2,294,024	2 40
Rights of way	180,884	178,234	20 40
Buildings	8,225	8,224	40
Furniture and equipment	10,904	10,305	3 7
Other	14,774	14,761	3 10
	2,627,530	2,505,548	
Less accumulated depreciation	(327,563)	(305,167)	
	$ 2,299,967	$ 2,200,381	

The Partnership recorded depreciation expense on property, plant and equipment, including capital lease arrangements (see Note 12), of $22.3 million and $15.0 million for the three months ended March 31, 2013 and 2012, 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 6.1% and 6.7% for the three months ended March 31, 2013 and 2012, respectively. The amount of interest capitalized was $2.5 million and $2.2 million for the three months ended March 31, 2013 and 2012, respectively.

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NOTE 6 GOODWILL AND INTANGIBLE ASSETS

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership reflected goodwill on its consolidated balance sheets of $319.3 million at both March 31, 2013 and December 31, 2012. The goodwill is related to acquisitions completed during the year ended December 31, 2012, including the Cardinal Acquisition. The goodwill related to the Cardinal Acquisition is a result of the strategic industry position and potential future synergies.

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, 2013 and December 31, 2012 (in thousands):

	March 31, 2013	December 31, 2012	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	$ 111,500	$ 119,933	10-14
Customer relationships	205,313	205,313	7 10
	316,813	325,246	
Accumulated amortization:			
Customer contracts	(3,112)	(746)	
Customer relationships	(130,915)	(125,140)	
	(134,027)	(125,886)	
Net carrying amount:			
Customer contracts	108,388	119,187	
Customer relationships	74,398	80,173	
Net carrying amount	$ 182,786	$ 199,360	

The weighted-average amortization period for customer contracts and customer relationships is 9.8 years and 9.1 years, respectively. The Partnership recorded amortization expense on intangible assets of $8.1 million and $5.8 million for the three months ended March 31, 2013 and 2012, 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 2013 - $25.7 million; 2014 $30.7 million; 2015 through 2016 - $25.7 million per year; 2017 - $19.6 million.

The Partnership completed an acquisition of a gas gathering system and related assets in June 2012. The Partnership accounted for the acquisition as a business combination and initially recognized $10.6 million related to customer contracts with an estimated useful life of 14 years. The initial recording of the transaction was based upon preliminary valuation assessments. The Partnership completed its assessments of the fair value of assets acquired and liabilities assumed during the three months ended March 31, 2013 and adjusted the final purchase price allocation, including an $8.4 million reduction of the fair value of intangible assets with finite lives.

The valuation assessment for the Cardinal Acquisition has not been completed as of March 31, 2013. The estimates of fair value of goodwill and intangible assets with finite lives reflected as of March 31, 2013 are subject to change and the change may be material. Revision to these estimates will be recorded retrospectively (see Note 3).

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NOTE 7 OTHER ASSETS

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

	March 31, 2013	December 31, 2012
Deferred finance costs, net of accumulated amortization of $16,612 and $23,536 at March 31, 2013 and December 31, 2012, respectively	$ 36,686	$ 30,496
Security deposits	1,972	2,097
	$ 38,658	$ 32,593

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 12). During the three months ended March 31, 2013 and 2012, the Partnership incurred $13.0 million and $0.1 million deferred finance costs, respectively, related to various financing activities (see Note 12). 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 12). The Partnership recorded $5.3 million of accelerated amortization of deferred financing costs associated with the retirement of debt during the three months ended March 31, 2013, included in loss on early extinguishment of debt on the Partnership s consolidated statement of operations, related to the retirement of the 8.75% Senior Notes. There was no accelerated amortization of deferred financing costs during the three months ended March 31, 2012. Amortization expense of deferred finance costs, excluding accelerated amortization expense was $1.5 million and $1.2 million for the three months ended March 31, 2013 and 2012, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations. Amortization expense related to remaining deferred finance costs is estimated to be as follows for each of the next five calendar years: remainder of 2013 - $4.5 million; 2014 to 2016 - $6.0 million per year; 2017 - $3.9 million.

NOTE 8 INCOME TAXES

As part of the Cardinal Acquisition (see Note 3), the Partnership acquired APL Arkoma, Inc., a taxable subsidiary. The components of the federal and state income tax benefit of the Partnership s taxable subsidiary at March 31, 2013 are summarized as follows (in thousands):

	Three Months Ended March 31, 2013
Deferred benefit :	
Federal	$ (8)
State	(1)
Total income tax benefit	$ (9)

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The components of net deferred tax liabilities as of March 31, 2013 and December 31, 2012 consist of the following (in thousands):

	March 31, 2013	December 31, 2012
Deferred tax assets:		
Net operating loss tax carryforwards and alternative minimum tax credits	$ 10,864	$ 10,277
Deferred tax liabilities:		
Excess of asset carrying value over tax basis	(41,113)	(40,535)
Net deferred tax liabilities	$ (30,249)	$ (30,258)

As of March 31, 2013, the Partnership had net operating loss carry forwards for federal income tax purposes of approximately $27.9 million, which expire at various dates from 2029 to 2032. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 9 DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price risk management activities. The Partnership uses financial swap and put 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. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under its swap agreements, the Partnership receives a fixed price and remits a floating price based on certain indices for the relevant contract period. The swap agreement sets a fixed price for the product being hedged. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. A costless collar is a combination of a purchased put option and a sold call option, in which the premiums net to zero. A costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

The Partnership no longer applies hedge accounting for derivatives. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. The change in fair value of commodity-based derivative instruments, which was previously recognized in accumulated other comprehensive loss within equity on the Partnership s consolidated balance sheets, was reclassified to the Partnership s consolidated statements of operations at the time the originally hedged physical transactions affected earnings.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of setoff at the time of settlement of the derivatives. 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. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership s consolidated balance sheets as the initial value of the options. Changes in the fair value of the options are recognized within derivative gain (loss), net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premiums are reclassified to realized gain (loss) within derivative gain (loss), net at the time the option expires or is exercised. The Partnership reflected net derivative assets on its consolidated balance sheets of $18.2 million and $31.0 million at March 31, 2013 and December 31, 2012, respectively.

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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, 2013:			
Current portion of derivative assets	$ 19,872	$ (2,481)	$ 17,391
Long-term portion of derivative assets	4,570	(2,192)	2,378
Long-term portion of derivative liabilities	3,248	(3,248)	
Total derivative assets, net	$ 27,690	$ (7,921)	$ 19,769
As of December 31, 2012:			
Current portion of derivative assets	$ 23,534	$ (457)	$ 23,077
Long-term portion of derivative assets	9,637	(1,695)	7,942
Total derivative assets, net	$ 33,171	$ (2,152)	$ 31,019

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, 2013:			
Current portion of derivative assets	$ (2,481)	$ 2,481	$
Long-term portion of derivative assets	(2,192)	2,192	
Current portion of derivative liabilities	(619)		(619)
Long-term portion of derivative liabilities	(4,173)	3,248	(925)
Total derivative liabilities, net	$ (9,465)	$ 7,921	$ (1,544)
As of December 31, 2012:			
Current portion of derivative liabilities	$ (457)	$ 457	$
Long-term portion of derivative liabilities	(1,695)	1,695	
Total derivative liabilities, net	$ (2,152)	$ 2,152	$

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The following table summarizes the Partnership s commodity derivatives as of March 31, 2013, (dollars and volumes in thousands):

Production Period	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Fixed price swaps				
2013	Natural gas	3,130	$ 3.61	$ (1,692)
2014	Natural gas	12,000	3.96	(3,065)
2015	Natural gas	12,100	4.21	(1,091)
2016	Natural gas	1,200	4.40	23
2013	NGLs	41,454	1.27	11,727
2014	NGLs	46,746	1.22	1,177
2015	NGLs	23,688	1.11	(1,111)
2013	Crude oil	252	97.05	32
2014	Crude oil	303	92.38	(222)
Total fixed price swaps				5,778
Options				
Purchased put options				
2013	Natural gas	600	4.13	270
2013	NGLs	32,508	1.88	4,712
2013	Crude oil	216	100.10	1,287
2014	Crude oil	389	95.24	3,517
2015	Crude oil	270	89.18	2,661
Total options				12,447
Total derivatives				$ 18,225

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.
(2) See Note 10 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, 2013	For the Three Months ended March 31, 2012
Derivatives previously designated as cash flow hedges		
Loss reclassified from accumulated other comprehensive loss into natural gas and liquids sales	$	$ (1,146)
Derivatives not designated as hedges		
Loss recognized in derivative loss, net		
Commodity contract - realized(1)	$ 1,636	$ (763)
Commodity contract - unrealized(2)	(13,719)	(11,272)
Derivative loss, net	$ (12,083)	$ (12,035)

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

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NOTE 10 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.

The Partnership uses a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 9). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership has a financial risk management committee (the Financial Risk Management Committee), which sets the policies, procedures and valuation methods utilized by the Partnership to value its derivative contracts. The Financial Risk Management Committee members include, among others, the Chief Executive Officer, the Chief Financial Officer and the Vice Chairman of the managing board of the General Partner. The Financial Risk Management Committee receives daily reports and meets on a weekly basis to review the risk management portfolio and changes in the fair value in order to determine appropriate actions.

Derivative Instruments

At March 31, 2013, 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

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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.

The following table represents the Partnership s derivative assets and liabilities recorded at fair value as of March 31, 2013 and December 31, 2012 (in thousands):

	Level 1	Level 2	Level 3	Total
March 31, 2013				
Assets				
Commodity swaps	$	$ 1,141	$ 14,102	$ 15,243
Commodity options		7,735	4,712	12,447
Total assets		8,876	18,814	27,690
Liabilities				
Commodity swaps		(7,156)	(2,309)	(9,465)
Total liabilities		(7,156)	(2,309)	(9,465)
Total derivatives	$	$ 1,720	$ 16,505	$ 18,225
December 31, 2012				
Assets				
Commodity swaps	$	$ 2,007	$ 17,573	$ 19,580
Commodity options		7,322	6,269	13,591
Total assets		9,329	23,842	33,171
Liabilities				
Commodity swaps		(1,393)	(759)	(2,152)
Total liabilities		(1,393)	(759)	(2,152)
Total derivatives	$	$ 7,936	$ 23,083	$ 31,019

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, 2013 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance December 31, 2012	87,066	$ 16,814	38,556	$ 6,269	$ 23,083
New contracts[1]	39,312		1,260	88	88
Cash settlements from unrealized gain (loss)[2][3]	(14,490)	(3,888)	(7,308)	2,044	(1,844)
Net change in unrealized gain (loss)[2]		(1,133)		(1,290)	(2,423)
Deferred option premium recognition[3]				(2,399)	(2,399)
Balance March 31, 2013	111,888	$ 11,793	32,508	$ 4,712	$ 16,505

(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 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, 2013 and December 31, 2012 (in thousands):

	Gallons	Third Party Quotes(1)	Adjustments(2)	Total Amount
As of March 31, 2013				
Propane swaps	92,736	$ 9,906	$ (319)	$ 9,587
Isobutane swaps	630	48	78	126
Normal butane swaps	5,040	233	134	367
Natural gasoline swaps	13,482	3,978	(2,265)	1,713
Total NGL swaps March 31, 2013	111,888	$ 14,165	$ (2,372)	$ 11,793
As of December 31, 2012				
Propane swaps	69,678	$ 16,302	$ (552)	$ 15,750
Isobutane swaps	1,134	(219)	187	(32)
Normal butane swaps	6,174	(909)	242	(667)
Natural gasoline swaps	10,080	3,247	(1,484)	1,763
Total NGL swaps December 31, 2012	87,066	$ 18,421	$ (1,607)	$ 16,814

(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, 2013:				
Propane	$ (319)	0.8969	0.9069	0.9019
Isobutane	78	1.1274	1.1366	1.1320
Normal butane	134	1.0384	1.0430	1.0407
Natural gasoline	(2,265)	0.9063	0.9251	0.9157
Total Level 3 adjustments March 31, 2013	$ (2,372)			
As of December 31, 2012:				
Propane	$ (552)	0.9019	0.9122	0.9071
Isobutane	187	1.1285	1.1376	1.1331
Normal butane	242	1.0370	1.0416	1.0393
Natural gasoline	(1,484)	0.8988	0.9169	0.9078
Total Level 3 adjustments December 31, 2012	$ (1,607)			

The Partnership had $7.8 million of NGL linefill at both March 31, 2013 and December 31, 2012, 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 is defined as a Level 3 asset and is valued using the same forward price curve utilized to

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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, 2013 and December 31, 2012, respectively.

The following table provides a summary of changes in fair value of the Partnership s NGL linefill for the three months ended March 31, 2013 (in thousands):

	NGL Linefill	
	Gallons	Amount
Balance December 31, 2012	9,148	$ 7,783
Net change in NGL linefill valuation(1)		(32)
Balance March 31, 2013	9,148	$ 7,751

(1) Included within natural gas and liquid 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 originally agreed to pay up to an additional $12.0 million, payable in two equal amounts, if certain volumes are achieved on the acquired gathering system within a specified time period (Trigger Payments). Sufficient volumes were achieved in December 2012 and the Partnership paid the first Trigger Payment of $6.0 million in January 2013. As of March 31, 2013, the fair value of the remaining Trigger 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 Trigger 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 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 12) 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, 2013 and December 31, 2012, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were $1,329.0 million and $1,216.4 million, respectively, compared with the carrying amounts of $1,318.9 million and $1,179.9 million, respectively.

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Acquisitions

On December 20, 2012, the Partnership completed the Cardinal 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. As of March 31, 2013, the accounting for the Cardinal Acquisition has not been completed. The estimates of fair value as of the acquisition date, which are reflected as of March 31, 2013, are subject to change and the changes made could be material. Revisions to these estimates will be recorded retrospectively.

NOTE 11 ACCRUED LIABILITIES

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

	March 31, 2013	December 31, 2012
Accrued capital expenditures	$ 9,362	$ 8,336
Cardinal Acquisition payable (offset by funds in escrow)	25,001	25,000
Acquisition-based short-term contingent consideration		6,000
Accrued ad valorem taxes	6,782	3,950
Other	5,862	14,466
	$ 47,007	$ 57,752

NOTE 12 DEBT

Total debt consists of the following (in thousands):

	March 31, 2013	December 31, 2012
Revolving credit facility	$ 154,500	$ 293,000
8.750% Senior notes due 2018		370,184
6.625% Senior notes due 2020	505,063	505,231
5.875% Senior notes due 2023	650,000	
Capital lease obligations	9,349	11,503
Total debt	1,318,912	1,179,918
Less current maturities	(8,861)	(10,835)
Total long term debt	$ 1,310,051	$ 1,169,083

Cash payments for interest related to debt, net of capitalized interest, were a net expense of $22.1 million for the three months ended March 31, 2013 and a net credit of $0.6 million for the three months ended March 31, 2012.

Revolving Credit Facility

At March 31, 2013, the Partnership had a $600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. Borrowings under the revolving credit facility bear interest, at the Partnership s option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% and (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at March 31, 2013, was 2.5%. 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, 2013. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At March 31, 2013, the Partnership had $445.4 million of remaining committed capacity under its revolving credit facility.

Borrowings under the revolving credit facility are secured by (i) a lien on and security interest in all the Partnership s property and that of its subsidiaries, except for the assets owned by Atlas Pipeline Mid-Continent WestOk, LLC (WestOK LLC) and Atlas Pipeline Mid-Continent WestTex, LLC (WestTX LLC), entities in which the Partnership has 95% interests, and Centrahoma, in which the Partnership has a 60% interest; and their respective subsidiaries; and (ii) by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including requirements that the Partnership maintain certain financial thresholds and restrictions on the Partnership s ability to (1) incur additional indebtedness, (2) make certain acquisitions, loans or investments, (3) make distribution payments to its unitholders if an event of default exists, or (4) enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is unable to borrow under its revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement.

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 Partnership s General Partner. As of March 31, 2013, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At March 31, 2013, the Partnership had $500.0 million principal outstanding of 6.625% unsecured senior notes due October 1, 2020 (6.625% Senior Notes) and $650.0 million principal outstanding of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes, and with the 6.625% Senior Notes, the Senior Notes).

The 6.625% Senior Notes are presented combined with a net $5.1 million unamortized premium as of March 31, 2013. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable at any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

In connection with the issuance of the 6.625% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by September 23, 2013 in the case of the 6.625% Senior Notes issued in September 2012, or by December 15, 2013, in the case of the 6.625% Senior Notes issued in December 2012. If the Partnership does not meet the aforementioned deadline, the 6.625% Senior Notes issued on September 28, 2012 and December 20, 2012 will be subject to additional interest, up to 1% per annum, until such time that the Partnership causes the exchange offer to be consummated. On April 12, 2013, the Partnership filed an amendment to its registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement, and the registration statement was declared effective by the SEC on April 12, 2013.

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 $637.1 million after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes) and repay a portion of the outstanding indebtedness under the revolving credit agreement. Interest on the 5.875% Senior Notes is payable semi-annually in arrears on February 1 and August 1. The 5.875% Senior Notes are redeemable any time after February 1, 2018, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

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In connection with the issuance of the 5.875% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by February 6, 2014. If the Partnership does not meet the aforementioned deadline, the 5.875% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the Partnership causes the exchange offer to be consummated.

On January 28, 2013, the Partnership commenced a cash tender offer for any and all of its outstanding $365.8 million 8.75% Senior Notes, excluding unamortized premium, 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. The Partnership also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer.

On March 12, 2013, the Partnership paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes 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. For the three months ended March 31, 2013, the Partnership recorded a loss of $26.6 million within loss on early extinguishment of debt on the Partnership s consolidated statements of operations, related to the redemption of the 8.75% Senior Notes. The loss includes $17.5 million premiums paid; $8.0 million consent payment; $5.3 million write off of deferred financing costs, offset by $4.2 million recognition of unamortized premium.

The Senior Notes are subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its revolving credit facility.

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, 2013.

Capital Leases

The following is a summary of the leased property under capital leases as of March 31, 2013 and December 31, 2012, which are included within property, plant and equipment (see Note 5) (in thousands):

	March 31, 2013	December 31, 2012
Pipelines, processing and compression facilities	$ 15,457	$ 15,457
Less accumulated depreciation	(1,277)	(1,066)
	$ 14,180	$ 14,391

Depreciation expense for leased properties was $211 thousand and $167 thousand for the three months ended March 31, 2013 and 2012, respectively, which is included within depreciation and amortization expense on the Partnership s consolidated statements of operations (see Note 5).

NOTE 13 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. During the three months ended March 31, 2013 and 2012, the Partnership paid $3.0 million and $2.5 million, respectively, for transportation fees related to these contracts. The future fixed and determinable portion of the obligations as of March 31, 2013 was as follows: remainder of 2013 - $7.0 million; 2014 - $9.5 million; and 2015 to 2017 - $3.5 million per year.

The Partnership had committed approximately $50.3 million for the purchase of property, plant and equipment at March 31, 2013.

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 14 BENEFIT PLANS

Generally, all share-based payments to employees, which are not cash settled, including grants of unit options and phantom units, are recognized within equity in the financial statements based on their fair values on the date of the grant. Share-based payments to non-employees, which have a cash settlement option, are recognized within liabilities in the financial statements based upon their current fair market value.

A phantom unit entitles a grantee to receive a common limited partner unit upon vesting of the phantom unit. In tandem with phantom unit grants, participants may be granted a distribution equivalent right (DER), 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 compensation committee appointed by the General Partner s managing board (the Compensation Committee) determines the vesting period for phantom units.

A unit option entitles a grantee to purchase a common limited partner unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option is equal to the fair market value of the common unit on the date of grant of the option. The Compensation Committee determines how the exercise price may be paid by the grantee as well as the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. There were no unit options outstanding as of March 31, 2013.

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. 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, 2013, the Partnership had 1,057,083 phantom units outstanding under the Partnership s LTIPs, with 1,517,513 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options, which have vested and have been exercised.

Partnership Phantom Units. Through March 31, 2013, phantom units granted to employees under the LTIPs generally had vesting periods of four 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, 2013, there were 292,809 units outstanding under the LTIPs that will vest within the following twelve months.

All phantom units outstanding under the LTIPs at March 31, 2013 include DERs granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were $0.6 million and $0.2 million, during the three month ended March 31, 2013 and 2012, respectively. These amounts were recorded as reductions of equity on the Partnership s consolidated balance sheets.

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

	Three Months Ended March 31,			
	2013		2012	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	1,053,242	$ 33.21	394,489	$ 21.63
Granted	6,804	33.06	4,132	36.29
Matured and issued(2)	(2,963)	28.94	(8,054)	39.78
Outstanding, end of period(3)(4)	1,057,083	$ 33.22	390,567	$ 21.41
Matured and not issued(5)		$	4,125	$ 44.51
Non-cash compensation expense recognized (in thousands)		$ 4,384		$ 978

(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, 2013 and 2012 were $0.1 million and $0.3 million, respectively.
(3) The aggregate intrinsic value for phantom unit awards outstanding at March 31, 2013 and 2012 was $36.6 million and $13.8 million, respectively.
(4) There were 21,767 and 16,692 outstanding phantom unit awards at March 31, 2013 and 2012, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.
(5) The aggregate intrinsic value for phantom unit awards vested but not issued at March 31, 2012 was $152 thousand.

At March 31, 2013, the Partnership had approximately $19.1 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 2.2 years.

NOTE 15 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 $0.9 million for the three months ended March 31, 2013 and 2012, 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, 2013 and 2012. 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, 2013 and 2012, respectively.

NOTE 16 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 Arkoma, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma and Permian Basins; 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) contract gas treating operations located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford; and (2) the Partnership s 20% interest in the equity income generated by West Texas LPG Pipeline Limited Partnership, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Contract gas treating revenues are primarily derived from monthly lease fees for use of treating facilities. Pipeline revenues are primarily derived from transportation fees.

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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, 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 venture		2,040		2,040
Loss on early extinguishment of debt			(26,582)	(26,582)
Income tax expense (benefit)	(9)			(9)
Net income (loss)	$ 41,661	$ 2,861	$ (72,014)	$ (27,492)
Three Months Ended March 31, 2012:				
Revenue:				
Revenues third party[1]	$ 305,388	$	$ (13,181)	$ 292,207
Revenues affiliates	79			79
Total revenues	305,467		(13,181)	292,286
Costs and expenses:				
Operating costs and expenses	247,167	83		247,250
General and administrative[1]			9,945	9,945
Other costs	(34)			(34)
Depreciation and amortization	20,842			20,842
Interest expense[1]			8,708	8,708
Total costs and expenses	267,975	83	18,653	286,711
Equity income in joint venture		896		896
Net income (loss)	$ 37,492	$ 813	$ (31,834)	$ 6,471

(1) The Partnership notes 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,	
	2013	**2012**
Capital Expenditures:		
Gathering and processing	$ 108,393	$ 81,167
Transportation and treating	123	
	$ 108,516	$ 81,167

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Balance Sheet	March 31, 2013	December 31, 2012
Equity method investment in joint venture:		
Transportation and Treating	$ 86,242	$ 86,002
Goodwill:		
Gathering and Processing	292,448	292,448
Transportation and Treating	26,837	26,837
	$ 319,285	$ 319,285
Total assets:		
Gathering and Processing	$ 2,926,959	$ 2,831,639
Transportation and Treating	139,809	141,356
Corporate and other	87,662	92,643
	$ 3,154,430	$ 3,065,638

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, 2013	2012
Natural gas and liquids sales:		
Natural gas	$ 141,484	$ 78,705
NGLs	217,831	188,694
Condensate	24,565	22,098
Other	(32)	(272)
Total	$ 383,848	$ 289,225

NOTE 17 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, 2013 and December 31, 2012 and for the three months ended March 31, 2013 and 2012 include the financial statements of WestOK LLC, WestTX LLC, and Centrahoma. 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, 2013 and December 31, 2012 and for the three months ended March 31, 2013 and 2012. 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):

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Balance Sheets

March 31, 2013	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 157	$ 8,104	$	$ 8,261
Accounts receivable affiliates	382,018			(382,018)	
Other current assets	210	83,142	134,621	(1,120)	216,853
Total current assets	382,228	83,299	142,725	(383,138)	225,114
Property, plant and equipment, net		497,992	1,801,975		2,299,967
Intangible assets, net		91,099	91,687		182,786
Goodwill		278,423	40,862		319,285
Equity method investment in joint venture		86,242			86,242
Long term portion of derivative asset		2,378			2,378
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	2,451,114	1,546,753		(3,997,867)	
Other assets, net	36,686	1,772	200		38,658
Total assets	$ 2,870,028	$ 2,587,958	$ 3,930,377	$ (6,233,933)	$ 3,154,430
Liabilities and Equity					
Accounts payable affiliates	$	$ 275,492	$ 110,864	$ (382,018)	$ 4,338
Other current liabilities	5,531	81,035	161,155		247,721
Total current liabilities	5,531	356,527	272,019	(382,018)	252,059
Long-term debt, less current portion	1,309,563	488			1,310,051
Long-term portion of derivative liability		925			925
Deferred income taxes, net		30,249			30,249
Other long-term liability	146	212	6,000		6,358
Equity	1,554,788	2,199,557	3,652,358	(5,851,915)	1,554,788
Total liabilities and equity	$ 2,870,028	$ 2,587,958	$ 3,930,377	$ (6,233,933)	$ 3,154,430
December 31, 2012					
Assets					
Cash and cash equivalents	$	$ 157	$ 3,241	$	$ 3,398
Accounts receivable affiliates	921,702			(921,702)	
Other current assets	172	68,144	149,507	(1,146)	216,677
Total current assets	921,874	68,301	152,748	(922,848)	220,075
Property, plant and equipment, net		491,790	1,708,591		2,200,381
Intangible assets, net		101,446	97,914		199,360
Goodwill		278,423	40,862		319,285
Equity method investment in joint venture		86,002			86,002
Long term portion of derivative asset		7,942			7,942
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,832,652	1,880,155		(3,712,807)	
Other assets, net	30,496	1,772	325		32,593
Total assets	$ 2,785,022	$ 2,915,831	$ 3,853,368	$ (6,488,583)	$ 3,065,638

Liabilities and Equity					
Accounts payable affiliates	$	$ 145,436	$ 781,766	$ (921,702)	$ 5,500
Other current liabilities	10,046	61,333	176,640		248,019
Total current liabilities	10,046	206,769	958,406	(921,702)	253,519
Long-term debt, less current portion	1,168,415	604	64		1,169,083
Deferred income taxes, net		30,258			30,258
Other long-term liability	153	217	6,000		6,370
Equity	1,606,408	2,677,983	2,888,898	(5,566,881)	1,606,408
Total liabilities and equity	$ 2,785,022	$ 2,915,831	$ 3,853,368	$ (6,488,583)	$ 3,065,638

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Statements of Operations

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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	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)
Three Months Ended March 31, 2012					
Total revenues	$	$ 48,987	$ 243,299	$	$ 292,286
Total costs and expenses	(8,350)	(70,083)	(208,278)		(286,711)
Equity income	13,285	34,904		(47,293)	896
Net income (loss)	4,935	13,808	35,021	(47,293)	6,471
Income attributable to non-controlling interest			(1,536)		(1,536)
Net income (loss) attributable to common limited partners and the General Partner	4,935	13,808	33,485	(47,293)	4,935
Other comprehensive income adjustment for realized losses on derivatives reclassified to net income	1,146	1,146		(1,146)	1,146
Comprehensive income (loss)	$ 6,081	$ 14,954	$ 33,485	$ (48,439)	$ 6,081

Statements of Cash Flows

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended March 31, 2013					
Net cash provided by (used in):					
Operating activities	$ (58,592)	$ 33,933	$ 56,426	$ 3,489	$ 35,256
Investing activities	(21,541)	(2,534)	(105,856)	21,541	(108,390)
Financing activities	80,133	(31,399)	54,293	(25,030)	77,997
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
Three Months Ended March 31, 2012					
Net cash provided by (used in):					

Operating activities	$ (63,078)	$ 31,874	$ 43,327	$ 30,624	$ 42,747
Investing activities	7,010	54,442	(82,786)	(76,942)	(98,276)
Financing activities	56,068	(86,316)	39,459	46,318	55,529
Net change in cash and cash equivalents					
Cash and cash equivalents, beginning of period		168			168
Cash and cash equivalents, end of period	$	$ 168	$	$	$ 168

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NOTE 18 SUBSEQUENT EVENTS

On April 16, 2013, Atlas Pipeline Mid-Continent Holdings, LLC, a wholly owned subsidiary of the Partnership, entered into a definitive agreement with TEAK Midstream Holdings, LLC and its wholly owned subsidiary TEAK Midstream, L.L.C. (TEAK) to purchase 100% of the outstanding ownership interests in TEAK for $1.0 billion in cash, subject to customary purchase price adjustments (the TEAK Acquisition). TEAK s assets primarily include gas gathering, processing and treating facilities in South Texas. Closing of the pending TEAK Acquisition is subject to customary closing conditions and is expected to occur in May 2013, with an effective date of April 1, 2013.

On April 16, 2013, the Partnership executed a Class D preferred unit purchase agreement for a private placement of $400.0 million of its Class D convertible preferred units (Class D Preferred Units) to third party investors, at a negotiated price per unit of $30.41, subject to adjustment. The Class D Preferred Units will be offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The issuance of the Class D Preferred Units is subject to customary closing conditions and is conditioned upon the closing of the TEAK Acquisition. The Partnership will have the right to convert the Class D Preferred Units, in whole but not in part, beginning one year following their issuance, into common units, subject to customary anti-dilution adjustments. Unless previously converted, all Class D Preferred Units will convert into common units at the end of eight full quarterly periods following their issuance. The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance, 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 Partnership s General Partner. Distributions will be determined based upon the cash distribution declared each quarter on the Partnership s common limited partner units. Upon the issuance of the Class D Preferred Units the Partnership will enter into a registration rights agreement pursuant to which it will agree to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class D Preferred Units. The Partnership will agree to use its commercially reasonable efforts to have the registration statement declared effective within 180 days of the date of conversion. The General Partner will also contribute $8.2 million to maintain its 2% general partnership interest, upon the issuance of the Class D Preferred Units. The Partnership expects to use all of the proceeds to fund a portion of the purchase price of the TEAK Acquisition.

On April 17, 2013, the Partnership entered into an underwriting agreement for the sale and issuance of 11,845,000 common units of the Partnership (including 1,545,000 common units to cover the underwriters over-allotment option) at a price to the public of $34.00 per unit. The underwriters exercised their over-allotment option in full on April 18, 2013. The Partnership received $388.4 million in proceeds after underwriting commissions and estimated expenses, plus the General Partner contributed $8.3 million to maintain its 2% general partnership interest. The Partnership expects to use all of the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition.

On April 19, 2013, the Partnership entered into an amendment to its credit agreement, which, among other changes, (1) allowed the pending TEAK Acquisition to be a Permitted Investment, as defined in the credit agreement; (2) will not require the joint venture interests, which will be acquired in the pending TEAK Acquisition, to be guarantors; (3) modified the definitions of Consolidated Funded Debt Ratio, Interest Coverage Ratio and Consolidated EBITDA to allow for an Acquisition Period whereby the terms for calculating each of these ratios have been adjusted; and (4) permitted the payment of cash distributions, if any, on the Class D 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.

On April 24, 2013, the Partnership declared a cash distribution of $0.59 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2013. The $49.3 million distribution, including $4.0 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on May 15, 2013 to unitholders of record at the close of business on May 8, 2013 (see Note 4).

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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, 2012. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

General

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, 2012.

Overview

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 and Treating.

The Gathering and Processing segment consists of (1) the Arkoma, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko, Arkoma and Permian Basins; 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, 2013, our Gathering and Processing operations, own, have interests in and operate twelve natural gas processing plants with aggregate capacity of approximately 1,090 MMCFD located in Oklahoma and Texas; a gas treating facility located in Oklahoma; and approximately 10,100 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; and the Barnett Shale. Our gathering systems are connected to approximately 8,600 receipt points, consisting primarily of 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 operations consist of (1) seventeen gas treating facilities used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas; and (2) a 20% interest in WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. The contract gas treating operations 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 (Chevron NYSE: CVX), which owns the remaining 80% interest.

Recent Events

On January 7, 2013, we paid $6.0 million for the first of two contingent payments related to the acquisition of a gas gathering system and related assets in February 2012. We agreed to pay up to an additional $12.0 million, payable in two equal amounts, if certain volumes were achieved on the acquired gathering system within specified periods of time. Sufficient volumes were achieved in December 2012 to meet the required volumes for the first contingent payment.

On February 11, 2013, we issued $650.0 million of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes) in a private placement transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.1 million and utilized the proceeds to redeem our outstanding 8.75% senior unsecured notes due June 15, 2018 (8.75% Senior Notes) and repay a portion of our outstanding indebtedness under our revolving credit facility.

Prior to issuance of the 5.875% Senior Notes and in anticipation thereof, on January 28, 2013, we commenced a cash tender offer for any and all of our outstanding $365.8 million 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 (representing approximately 73.4% of the outstanding 8.75% Senior Notes), were validly tendered as of the expiration date of the consent solicitation. In February 2013, we accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture. We also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer.

On March 12, 2013, we paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes plus a $6.3 million make-whole premium and $2.0 million in accrued interest. We funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

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Subsequent Events

On April 16, 2013 we entered into a definitive agreement with TEAK Midstream Holdings, LLC and its wholly owned subsidiary TEAK Midstream, L.L.C. (TEAK) to purchase 100% of the outstanding ownership interests in TEAK for $1.0 billion in cash, subject to customary purchase price adjustments (the TEAK Acquisition). TEAK s assets primarily include gas gathering, processing and treating facilities in South Texas. Closing of the pending TEAK Acquisition is subject to customary closing conditions and is expected to occur in May 2013, with an effective date of April 1, 2013.

On April 16, 2013, we executed a Class D preferred unit purchase agreement for a private placement of $400 million of Class D convertible preferred units (Class D Preferred Units) to third party investors, at a negotiated price per unit of $30.41, subject to adjustment. The Class D Preferred Units will be offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The issuance of the Class D Preferred Units is subject to customary closing conditions, conditioned upon the closing of the TEAK Acquisition. We will have the right to convert the Class D Preferred Units, in whole but not in part, beginning one year following their issuance, into common units, subject to customary anti-dilution adjustments. Unless previously converted, all Class D Preferred Units will convert into common units at the end of eight full quarterly periods following their issuance. The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance, 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. Distributions will be determined based upon the cash distribution declared each quarter for payment on our common limited partner units. Upon the issuance of the Class D Preferred Units, we will enter into a registration rights agreement pursuant to which we will agree to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class D Preferred Units. We will agree to use its commercially reasonable efforts to have the registration statement declared effective within 180 days of the date of conversion. The General Partner will also contribute $8.2 million to maintain its 2% general partnership interest, upon the issuance of the Class D Preferred Units. We expect to use all of the proceeds to fund a portion of the purchase price of the TEAK Acquisition.

On April 17, 2013, we entered into an underwriting agreement for the sale and issuance of 11,845,000 of our common units (including 1,545,000 common units to cover the underwriters over-allotment option) at a price to the public of $34.00 per unit. The underwriters exercised their over-allotment option in full on April 18, 2013. We received $388.4 million in proceeds after underwriting commissions and estimated expenses, plus the General Partner contributed $8.3 million to maintain its 2% general partnership interest. We expect to use all of the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition.

On April 19, 2013, we entered into an amendment to our credit agreement, which among other changes:

- allowed the pending TEAK Acquisition to be a Permitted Investment, as defined in the credit agreement;
- will not require the joint venture interests, which will be acquired in the pending TEAK Acquisition, to be guarantors;
- permitted the payment of cash distributions, if any, on the Class D 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; and

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- modified the definition of Consolidated Funded Debt Ratio, Interest Coverage Ratio and Consolidated EBITDA to allow for an Acquisition Period whereby the terms for calculating each of these ratios have been adjusted; and

- permitted the Consolidated Funded Debt Ratio to be greater than:

  - 5.50 to 1.00 for the last day of any fiscal quarter during an Acquisition Period (as defined by the credit agreement);

  - 5.75 to 1.00 for the last day of the fiscal quarter in which the TEAK Acquisition is consummated;

  - 5.50 to 1.00 for last day of the two fiscal quarters immediately following the fiscal quarter in which the TEAK Acquisition is consummated; or

  - 5.00 to 1.00 for the last day of any other fiscal quarter.

Acquisitions

In December 2012, we acquired 100% of the equity interests held by Cardinal Midstream, LLC (Cardinal) in three wholly-owned subsidiaries for $598.5 million in cash, including preliminary purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies represented the majority of the operating assets of Cardinal (the Arkoma system) and include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas as follows:

- the Tupelo plant, which is a 120 MMCFD cryogenic processing facility;

- approximately 60 miles of gathering pipeline;

- the East Rockpile treating facility, a 250 GPM amine treating plant;

- a fixed fee contract gas treating business that includes 15 amine treating plants and two propane refrigeration plants; and

- a 60% interest in a joint venture known as Centrahoma Processing, LLC (Centrahoma). The remaining 40% interest is owned by MarkWest Oklahoma Gas Company, LLC, (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE). Centrahoma owns the following assets:

  - the Coalgate and Atoka plants, which are cryogenic processing facilities with a combined current processing capacity of approximately 100 MMCFD;

  - the prospective Stonewall plant, for which construction has been approved, with anticipated processing capacity of 120 MMCFD; and

15 miles of NGL pipeline.

How We Evaluate Our Operations

Our principal revenue is generated from the gathering, processing and treating of natural gas and the sale of natural gas, NGLs and condensate. 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.

Revenue consists of the sale of natural gas, NGLs and condensate; and the fees earned from our gathering, processing and treating operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems and then sell the natural gas, NGLs and condensate off delivery points on our systems. Under other agreements, we gather natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Revenue Recognition for further discussion of contractual revenue arrangements).

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.

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 plus transportation, processing and other fees 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.

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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, gain (losses) on asset sales and other non-cash gain (losses).

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.

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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.

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, 2013 and 2012 (in thousands):

RECONCILIATION OF GROSS MARGIN

	Three Months Ended March 31,	
	2013	**2012**
Net income (loss)	$ (27,492)	$ 6,471
Adjustments:		
Derivative loss, net	12,083	12,035
Other income, net	(3,422)	(2,415)
Operating expenses(1)	22,389	14,111
General and administrative expense(2)	13,798	9,945
Depreciation and amortization	30,458	20,842
Interest	18,686	8,708
Income tax expense	(9)	
Equity income in joint venture	(2,040)	(896)
Loss on early extinguishment of debt	26,582	
Non-cash linefill (gain) loss(3)	32	272
Gross margin	$ 91,065	$ 69,073

(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.

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RECONCILIATION OF EBITDA, ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Net income (loss)	$ (27,492)	$ 6,471
Adjustments:		
Income attributable to non-controlling interests[1]	(1,369)	(1,536)
Interest expense	18,686	8,708
Income tax benefit	(9)	
Depreciation and amortization	30,458	20,842
Non-controlling interest depreciation, amortization and interest expense[2]	(850)	
EBITDA	19,424	34,485
Adjustments:		
Equity income in joint venture	(2,040)	(896)
Distributions from joint venture	1,800	1,800
Loss on early extinguishment of debt	26,582	
Non-cash loss on derivatives	13,719	10,696
Premium expense on derivative instruments	3,275	3,752
Acquisitions costs	530	
Non-cash compensation	4,384	978
Non-cash line fill (gain) loss[3]	32	272
Adjusted EBITDA	67,706	51,087
Adjustments:		
Interest expense	(18,686)	(8,708)
Amortization of deferred finance costs	1,544	1,165
Premium expense on derivative instruments	(3,275)	(3,752)
Other costs		(34)
Maintenance capital[4]	(3,814)	(4,510)
Distributable Cash Flow	$ 43,475	$ 35,248

(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 s non-controlling interest in 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 maintenance capital expenditures net of amounts attributable to non-controlling interest for MarkWest s interest in Centrahoma.

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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
		2013	2012	Change
Pricing:				
Weighted Average Market Prices:				
NGL price per gallon	Conway hub	$ 0.83	$ 0.93	(10.8)%
NGL price per gallon	Mt. Belvieu hub	0.85	1.18	(28.0)%
Natural gas sales ($/Mcf):				
Velma		3.17	2.55	24.3%
WestOK		3.20	2.56	25.0%
WestTX		3.12	2.51	24.3%
Weighted Average		3.17	2.54	24.8%
NGL sales ($/gallon):				
Arkoma		0.70		
Velma		0.75	0.93	(19.4)%
WestOK		0.98	0.91	7.7%
WestTX		0.93	1.17	(20.5)%
Weighted Average		0.84	1.03	(18.4)%
Condensate sales ($/barrel):				
Arkoma		87.92		
Velma		93.39	102.22	(8.6)%
WestOK		83.67	93.95	(10.9)%
WestTX		88.02	101.38	(13.2)%
Weighted Average		86.00	97.44	(11.7)%

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	Three Months Ended March 31, 2013	2012	Percent Change
Operating data:			
Arkoma system[(1)]:			
Gathered gas volume (MCFD)	260,732		
Processed gas volume (MCFD)	201,301		
Residue gas volume (MCFD)	207,844		
NGL volume (BPD)	20,555		
Condensate volume (BPD)	158		
Velma system:			
Gathered gas volume (MCFD)	130,767	129,223	1.2%
Processed gas volume (MCFD)	125,377	122,904	2.0%
Residue gas volume (MCFD)	102,238	100,335	1.9%
NGL volume (BPD)	13,997	13,643	2.6%
Condensate volume (BPD)	405	564	(28.2)%
WestOK system:			
Gathered gas volume (MCFD)	452,368	295,198	53.2%
Processed gas volume (MCFD)	425,431	279,305	52.3%
Residue gas volume (MCFD)	396,694	251,940	57.5%
NGL volume (BPD)	16,251	14,062	15.6%
Condensate volume (BPD)	1,969	1,405	40.1%
WestTX system[(1)]:			
Gathered gas volume (MCFD)	312,571	246,339	26.9%
Processed gas volume (MCFD)	280,756	230,504	21.8%
Residue gas volume (MCFD)	209,891	160,022	31.2%
NGL volume (BPD)	33,245	33,101	0.4%
Condensate volume (BPD)	1,033	939	10.0%
Barnett system:			
Average throughput volumes (MCFD)	21,401		
Tennessee system:			
Average throughput volumes (MCFD)	9,495	8,225	15.4%
WTLPG system[(1)]:			
Average NGL volumes (BPD)	244,626	242,318	1.0%

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

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The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2013 and 2012 (in thousands):

	Three Months Ended March 31, 2013	2012	Variance	Percent Change
Gross margin[1]				
Natural gas and liquids sales	$ 383,848	$ 289,225	$ 94,623	32.7%
Transportation, processing and other fees	32,725	12,681	20,044	158.1%
Less: non-cash line fill gain (loss)[2]	(32)	(272)	240	88.2%
Less: natural gas and liquids cost of sales	325,540	233,105	92,435	39.7%
Gross margin	91,065	69,073	21,992	31.8%
Expenses:				
Operating expenses	21,859	14,145	7,714	54.5%
General and administrative[3]	13,798	9,945	3,853	38.7%
Other costs	530	(34)	564	1658.8%
Depreciation and amortization	30,458	20,842	9,616	46.1%
Interest expense	18,686	8,708	9,978	114.6%
Total expenses	85,331	53,606	31,725	59.2%
Other income items:				
Derivative loss, net	(12,083)	(12,035)	(48)	(0.4)%
Other income, net	3,422	2,415	1,007	41.7%
Non-cash line fill gain (loss)[2]	(32)	(272)	240	88.2%
Equity income in joint venture	2,040	896	1,144	127.7%
Loss on early extinguishment of debt	(26,582)		(26,582)	(100.0)%
Income tax benefit	9		9	100.0%
Income attributable to non-controlling interests[4]	(1,369)	(1,536)	167	10.9%
Net income (loss) attributable to common limited partners and General Partner	$ (28,861)	$ 4,935	$ (33,796)	(684.8)%
Non-GAAP financial data:				
EBITDA[1]	$ 19,424	$ 34,485	$ (15,061)	(43.7)%
Adjusted EBITDA[1]	67,706	51,087	16,619	32.5%
Distributable cash flow[1]	43,475	35,248	8,227	23.3%

(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 any 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 the operating results of Centrahoma.

Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012

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, 2013 increased primarily due to higher production volumes, including the new volumes from the Arkoma system due to the Cardinal Acquisition, partially offset by lower commodity prices.

Volumes on the Velma system for the three months ended March 31, 2013 approximated the prior year period volumes.

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Volumes on the WestOK system increased for the three months ended March 31, 2013 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand; and the start-up of the Waynoka II plant.

WestTX system gathering and processing volumes for the three months ended March 31, 2013 increased compared to the prior year period due to increased volumes from Pioneer Natural Resources Company (NYSE: PXD) as a result of their continued drilling program.

Transportation, processing and other fees for the three months ended March 31, 2013 increased primarily due to $12.9 million in additional fee-based revenues generated on the Arkoma systems acquired in December 2012 (see Acquisitions) and due to increased processing fee revenue of $5.6 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, 2013 increased mainly due to $3.6 million in additional expenses from the Arkoma systems and a $2.8 million increase on the WestOK system primarily due to increased gathered volumes in comparison to the prior year period, as discussed above in Gross margin.

General and administrative expense, including amounts reimbursed to affiliates, increased for the three months ended March 31, 2013 mainly due to a $3.4 million increase in share-based compensation related to phantom units granted to employees (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 14).

Other costs for the three months ended March 31, 2013 increased mainly due to $0.5 million in acquisition costs related to the Cardinal Acquisition, which were recorded in the current year period (see Acquisitions).

Depreciation and amortization expense for the three months ended March 31, 2013 increased primarily due to $5.7 million additional expense related to assets acquired the Cardinal Acquisition (see Acquisitions) and due to growth capital expenditures incurred subsequent to March 31, 2012.

Interest expense for the three months ended March 31, 2013 increased primarily due to an $8.2 million increase in interest expense associated with the 6.625% unsecured senior notes due October 1, 2020 (6.625% Senior Notes) and $5.3 million additional interest related to the 5.875% Senior Notes, partially offset by $3.6 million reduced interest on the 8.75% Senior Notes. The increase in the interest on the 6.625% Senior Notes and the 5.875% Senior Notes is due to their issuance after March 31, 2012 (see Senior Notes). The decrease in the interest for the 8.75% Senior Notes is due to their redemption during the three months ended March 31, 2013 (see Senior Notes).

Other income items:

Derivative gain (loss), net for the three months ended March 31, 2013 had a $2.4 million favorable variance for realized settlements in the current period compared to the prior year period mainly as a result of lower NGL prices, offset by a $2.4 million unfavorable variance on the fair value revaluation of commodity derivative contracts in the current 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 9 for further discussion of derivative instrument valuations). We recognized a \$2.4 million and \$7.1 million mark-to-market loss on derivatives that were valued based upon unobservable inputs for the three months ended March 31, 2013 and 2012, 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, 2013 had a favorable 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.

Non-cash line fill gain (loss) had a favorable variance for the three months ended March 31, 2013 compared to the prior year period primarily due to the settlement of line fill on the Velma system during the prior year period.

Equity income in joint venture increased for the three months ended March 31, 2013 primarily due to increased revenues from our 20% ownership interest in WTPLG mainly as a result of a tariff rate increase after March 31, 2012.

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 Senior Notes).

Income tax benefit for the three months ended March 31, 2013 represents the accrued income tax related to the income earned on APL Arkoma, Inc., which was acquired as part of the Cardinal Acquisition (see Acquisitions).

Income attributable to non-controlling interests increased primarily due to Anadarko s non-controlling interest in higher net income for the WestOK joint venture, which was formed to accomplish our acquisition of control of the system. The increase in net income of the WestOK joint venture was principally due to higher gross margins on the sale of commodities, resulting from higher volumes.

Non-GAAP financial data:

EBITDA was lower for the three months ended March 31, 2013 compared to the prior year period mainly due to the loss on early extinguishment of debt recognized during the three months ended March 31, 2013, as discussed above in Other income items, combined with higher operating expenses as discussed above in Expenses, and partially offset by improved gross margin as discussed above in Gross Margin.

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Adjusted EBITDA had a favorable variance for the three months ended March 31, 2013 compared to the prior year period mainly due to the favorable gross margin variance, as discussed above in Gross margin , partially offset by higher operating expenses as discussed above in Expenses.

Distributable cash flow had a favorable variance for the three months ended March 31, 2013 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.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from operations and borrowings under our revolving credit facility. Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and quarterly distributions to our common unitholders and General Partner. In general, we expect to fund:

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through the retention of cash and additional capital raising; and
- debt principal payments through operating cash flows and refinancings as they become due, or by the issuance of additional limited partner units or asset sales.

At March 31, 2013, we had $154.5 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 $445.4 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, 2013. We had a working capital deficit of $26.9 million at March 31, 2013 compared with a $33.4 million working capital deficit at December 31, 2012. 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.

Instability in the financial markets, as a result of recession or otherwise, may cause volatility in the markets and may impact the availability of funds from those markets. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flows from operations and our revolving credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain additional capital will be available to the extent required and on acceptable terms.

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Cash Flows   Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012

The following table details the cash flow changes between the three months ended March 31, 2013 and 2012 (in thousands):

	Three Months Ended March 31,			
Net cash provided by (used in):	2013	2012	Variance	Percent Change
Operating activities	$ 35,256	$ 42,747	$ (7,491)	(17.5)%
Investing activities	(108,390)	(98,276)	(10,114)	10.3%
Financing activities	77,997	55,529	22,468	40.5%
Net change in cash and cash equivalents	$ 4,863	$	$ 4,863	

Net cash provided by operating activities for the three months ended March 31, 2013 decreased compared to the prior year period due to a $10.7 million unfavorable variance in the change in working capital, partially offset by a $3.2 million increase in net earnings from continuing operations excluding non-cash charges. The unfavorable change in working capital is partially due to the $6.0 million contingent payment made during the three months ended March 31, 2013 related to an acquisition in the prior year (see Recent Events). The increase in net earnings from continuing operations excluding non-cash charges is primarily due to increased gross margins from the sale of natural gas and NGLs partially offset by higher operating and interest expenses (see Results of Operations).

Net cash used in investing activities for the three months ended March 31, 2013 increased compared to the prior year period mainly due to a $27.3 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) and due to $17.2 million cash paid for acquisition of assets in the prior year period.

Net cash provided by financing activities for the three months ended March 31, 2013 increased compared to the prior year period mainly due to $637.1 million provided by the issuance of the 5.875% Senior Notes in the current period (see Senior Notes), partially offset by the $391.4 million redemption of the 8.75% Senior Notes, including the cost of early retirement of debt; $138.5 million used in the current period to reduce outstanding borrowings on the revolving credit facility; and $88.0 million in additional borrowings on our revolving credit facility in the prior period.

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,	
	2013	2012
Maintenance capital expenditures	$ 3,855	$ 4,510
Expansion capital expenditures	104,661	76,657

Total	$ 108,516	$ 81,167

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Expansion capital expenditures increased for the three months ended March 31, 2013 primarily due to the construction of the Driver Plant within WestTX. The decrease in maintenance capital expenditures for the three months ended March 31, 2013 compared with the prior year period was due to fluctuations in the timing of scheduled maintenance activity. As of March 31, 2013, we had approved additional expenditures of approximately $225.7 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately $50.3 million purchase commitments had been made. We expect to fund these projects through operating cash flows and borrowings under our existing revolving credit facility.

Partnership Distributions

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

Our General Partner is granted discretion 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% 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% 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 $2.3 million and $1.4 million were paid during the three months ended March 31, 2013 and 2012, respectively.

Off Balance Sheet Arrangements

As of March 31, 2013, 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.

Common Equity Offerings

We have an equity distribution program with Citigroup, through which we may offer and sell common units having an aggregate value of up to $150.0 million. Such sales will be at market prices prevailing at the time of the sale. There will be no specific date on which the offering will end and there will be no minimum purchase requirements. During the three months ended March 31, 2013, we issued 447,785 common units under the equity distribution program for net proceeds of $14.4 million, including $0.3 million in commission paid to Citigroup. We also received a capital contribution from the General Partner of $0.3 million to maintain its 2.0% general partner interest in us. The net proceeds from the common unit offering were utilized for general partnership purposes. As of March 31, 2013, we had $126.3 million remaining dollar capacity under the equity distribution program.

Revolving Credit Facility

At March 31, 2013, we had a $600.0 million senior secured revolving credit facility with a syndicate of banks, which matures in May 2017. Borrowings under the revolving credit facility bear interest, at our option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at March 31, 2013, was 2.5%. 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, 2013. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

Borrowings under the revolving credit facility are secured by a lien on and security interest in all our property and that of our subsidiaries, except for the assets owned by the WestOK, WestTX and Centrahoma joint ventures and their respective subsidiaries. Borrowings are also secured by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including covenants to maintain specified financial ratios, restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are also unable to borrow under our revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement.

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, 2013, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

At March 31, 2013, we had $500.0 million principal outstanding of 6.625% Senior Notes and $650.0 million principal outstanding of 5.875% Senior Notes (together with the 6.625% Senior Notes, the Senior Notes).

The 6.625% Senior Notes are presented combined with a net $5.1 million unamortized premium as of March 31, 2013. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable at any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

In connection with the issuance of the 6.625% Senior Notes, we entered into registration rights agreements, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by September 23, 2013 in the case of the 6.625% Senior Notes issued in September 2012, or by December 15, 2013, in the case of the 6.625% Senior Notes issued in December 2012. If we do not meet the aforementioned deadline, the 6.625% Senior Notes issued on September 28, 2012 and December 20, 2012 will be subject to additional interest, up to 1% per annum, until such time we consummate the exchange offer. On April 12, 2013, we filed an amendment to our registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement, and the registration statement was declared effective by the SEC on April 12, 2013.

On February 11, 2013, we issued $650.0 million of the 5.875% Senior Notes in a private transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.1 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 revolving credit agreement. Interest on the 5.875% Senior Notes is payable semi-annually in arrears on February 1 and August 1. The 5.875% Senior Notes are redeemable at any time after February 1, 2018, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

In connection with the issuance of the 5.875% Senior Notes, we entered into registration rights agreements, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by February 6, 2014. If we do not meet the aforementioned deadline, the 5.875% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that we cause the exchange offer to be consummated.

On January 28, 2013, we commenced a cash tender offer for any and all of our 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 8.75% Senior Notes Indenture. Approximately $268.4million aggregate principal amount of the 8.75% Senior Notes, were validly tendered as of the expiration date of the consent solicitation. In February 2013, we 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. We entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture. We also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer.

On March 12, 2013, we paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes plus a $6.3 million make-whole premium and $2.0 million in accrued interest. We funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

The Senior Notes are subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under the revolving credit facility.

Indentures governing the Senior Notes contain covenants, including limitations of our 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 our assets. We were in compliance with these covenants as of March 31, 2013

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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. Discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2. In addition to estimates discussed below, discussion of the potential impact of a change in critical accounting estimates is included within our Annual Report on Form 10-K for the year ended December 31, 2012.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Derivative Instruments		
Our derivative financial instruments are recorded at fair value in the consolidated balance sheets. Changes in fair value and settlements are reflected in our earnings in the consolidated statements of operations as gains and losses related to NGLs sales, interest expense and/or derivative loss, net. (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 10 for further discussion)	When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument s fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based upon inputs that are largely unobservable. These instruments are classified as Level 3 under the fair value hierarchy. The fair value of these instruments are determined based on pricing models developed primarily from historical and expected correlations with quoted market prices. At March 31, 2013, approximately 91% of our net derivative assets are classified as Level 3 with the remainder classified as Level 2.	If the assumptions used in the pricing models for our financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains that could be material. Of the $18.2 million and $31.0 million net derivative assets at March 31, 2013 and December 31, 2012, respectively, we had $16.5 million and $23.1 million net derivative assets at March 31, 2013 and December 31, 2012, respectively, that were classified as Level 3 fair value measurements, which rely on subjective forward developed price curves. Holding all other variables constant, a 10% change in the prices utilized in calculating the Level 3 fair value of derivatives at March 31, 2013 would have resulted in approximately a $12.8 million noncash change to net income for the three months ended March 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

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on March 31, 2013. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties to our commodity-based derivatives are banking institutions, or their affiliates, currently participating in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At March 31, 2013, we had a $600.0 million senior secured revolving credit facility with $154.5 million in outstanding borrowings. Borrowings under the revolving credit facility bear interest, at our option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for the revolving credit facility borrowings was 2.5% at March 31, 2013. Based upon the outstanding borrowings on the senior secured revolving credit facility and holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by approximately $1.5 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. We use a number of different derivative instruments in connection with our commodity price risk management activities. We enter into financial swap and option instruments to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual

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agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under swap agreements, we receive a fixed price and remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right to receive the difference between a fixed price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 9 for further discussion of our derivative instruments. Average estimated market prices for NGLs, natural gas and condensate, based upon twelve-month forward price curves as of April 5, 2013, were $0.85 per gallon, $4.26 per million BTU and $92.56 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended March 31, 2014 by approximately $13.1 million.

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, 2013, 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.

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, 2012.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Securities Purchase Agreement dated November 30, 2012, by and among Cardinal Midstream, LLC, Cardinal Arkoma, Inc., Cardinal Arkoma Midstream, LLC, Cardinal Gas Treating LLC and Atlas Pipeline Mid-Continent Holdings, LLC. The schedules to the Securities Purchase 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.[30]
2.2	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 6019c) 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]
4.1	Common unit certificate (attached as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership) [2]
4.2	8 3/4% Senior Notes Indenture dated June 27, 2008[7]
4.2(a)	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]
4.3(a)	6 5/8% Senior Notes Indenture dated September 28, 2012[26]
4.3(b)	Supplemental Indenture dated as of December 20, 2012[32]
4.4	5 7/8% Senior Notes Indenture dated as of February 11, 2013[10]
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]
10.2	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]

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Exhibit No.	Description
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]
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	Registration Rights Agreement, dated September 28, 2012, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein[26]
10.19	Registration Rights Agreement, dated December 20, 2012, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein [32]
10.20	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]
10.21	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]
10.22	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]
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[36]
101.SCH	XBRL Schema Document[36]
101.CAL	XBRL Calculation Linkbase Document[36]
101.LAB	XBRL Label Linkbase Document[36]
101.PRE	XBRL Presentation Linkbase Document[36]

101.DEF	XBRL Definition Linkbase Document[36]

(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 June 27, 2008.
(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.
(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 annual report on Form 10-K filed for the year ended December 31, 2011.
(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.
(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 December 4, 2012.
(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) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

Table of Contents

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 6, 2013	By: /s/ EUGENE N. DUBAY Eugene N. Dubay Chief Executive Officer, President and Managing Board Member of the General Partner
Date: May 6, 2013	By: /s/ ROBERT W. KARLOVICH, III Robert W. Karlovich, III Chief Financial Officer and Chief Accounting Officer of the General Partner