

ATLAS PIPELINE PARTNERS LP
Form 10-Q
May 07, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2012

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)

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DELAWARE
(State or other jurisdiction of
incorporation or organization)

23-3011077
(I.R.S. Employer
Identification No.)

Park Place Corporate Center One
1000 Commerce Drive, 4th Floor

Pittsburg, Pennsylvania
(Address of principal executive office)

15275-1011
(Zip code)

Registrant's telephone number, including area code: (877) 950-7473

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

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

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

Large accelerated filer 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

The number of common units of the registrant outstanding on May 3, 2012 was 53,625,237.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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Glossary of Terms

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

BPD	Barrels per day. Barrel measurement for a standard US barrel is 42 gallons. Crude oil and condensate are generally reported in barrels.
BTU	British thermal unit, a basic measure of heat energy
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
EBITDA	Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is 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
IFRS	International Financial Reporting Standards
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.
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

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

(in thousands)

(Unaudited)

	March 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 168	\$ 168
Accounts receivable	104,638	115,412
Current portion of derivative assets		1,645
Prepaid expenses and other	12,826	15,641
Total current assets	117,632	132,866
Property, plant and equipment, net	1,642,350	1,567,828
Intangible assets, net	108,070	103,276
Investment in joint ventures	85,975	86,879
Long-term portion of derivative assets	4,800	14,814
Other assets, net	22,091	25,149
Total assets	\$ 1,980,918	\$ 1,930,812
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	\$ 4,011	\$ 2,085
Accounts payable - affiliates	3,101	2,675
Accounts payable	35,732	54,644
Accrued liabilities	21,037	23,282
Accrued interest payable	9,755	1,624
Current portion of derivative liabilities	1,642	
Accrued producer liabilities	77,047	88,096
Total current liabilities	152,325	172,406
Long-term debt, less current portion	609,314	522,055
Other long-term liability	6,128	123
Commitments and contingencies		
Equity:		
General Partner's interest	23,293	23,856
Common limited partners' interests	1,219,929	1,245,163
Accumulated other comprehensive loss	(3,244)	(4,390)
Total partners' capital	1,239,978	1,264,629

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Non-controlling interest	(26,827)	(28,401)
Total equity	1,213,151	1,236,228
Total liabilities and equity	\$ 1,980,918	\$ 1,930,812

See accompanying notes to consolidated financial statements

Table of Contents**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED STATEMENTS OF OPERATIONS**

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31,	
	2012	2011
Revenue:		
Natural gas and liquids sales	\$ 289,225	\$ 266,309
Transportation, processing and other fees third parties	12,602	9,288
Transportation, processing and other fees affiliates	79	122
Derivative loss, net	(12,035)	(21,645)
Other income, net	2,415	2,789
Total revenues	292,286	256,863
Costs and expenses:		
Natural gas and liquids cost of sales	233,105	218,292
Plant operating	13,881	12,774
Transportation and compression	264	184
General and administrative	9,070	8,598
Compensation reimbursement affiliates	875	419
Other costs	(34)	
Depreciation and amortization	20,842	18,905
Interest	8,708	12,445
Total costs and expenses	286,711	271,617
Equity income in joint ventures	896	462
Gain on asset sale and other		255,947
Income from continuing operations	6,471	241,655
Loss on sale of discontinued operations		(81)
Net income	6,471	241,574
Income attributable to non-controlling interests	(1,536)	(1,187)
Preferred unit dividends		(240)
Net income attributable to common limited partners and the General Partner	\$ 4,935	\$ 240,147

Table of Contents**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED STATEMENTS OF OPERATIONS**

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31,	
	2012	2011
Allocation of net income (loss) attributable to:		
Common limited partner interest:		
Continuing operations	\$ 3,467	\$ 235,399
Discontinued operations		(79)
	3,467	235,320
General Partner interest:		
Continuing operations	1,468	4,829
Discontinued operations		(2)
	1,468	4,827
Net income (loss) attributable to:		
Continuing operations	4,935	240,228
Discontinued operations		(81)
	\$ 4,935	\$ 240,147
Net income attributable to common limited partners per unit:		
Basic	\$ 0.06	\$ 4.37
Weighted average common limited partner units (basic)	53,620	53,375
Diluted	\$ 0.06	\$ 4.37
Weighted average common limited partner units (diluted)	54,013	53,846

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,	
	2012	2011
Net income	\$ 6,471	\$ 241,574
Income attributable to non-controlling interests	(1,536)	(1,187)
Preferred unit dividends		(240)
Net income attributable to common limited partners and the General Partner	4,935	240,147
Other comprehensive income:		
Adjustment for realized losses on derivatives reclassified to net income	1,146	1,702
Comprehensive income	\$ 6,081	\$ 241,849

See accompanying notes to consolidated financial statements

Table of Contents**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED STATEMENT OF EQUITY****FOR THE THREE MONTHS ENDED March 31, 2012****(in thousands, except unit data)****(Unaudited)**

	Number of Limited Partner Common Units	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Non- controlling Interest	Total
Balance at December 31, 2011	53,617,183	\$ 1,245,163	\$ 23,856	\$ (4,390)	\$ (28,401)	\$ 1,236,228
Issuance of common units under incentive plans	8,054	77				77
Equity based compensation expense		928				928
Distributions paid		(29,706)	(2,031)			(31,737)
Distributions received from non-controlling interests					38	38
Other comprehensive income				1,146		1,146
Net income		3,467	1,468		1,536	6,471
Balance at March 31, 2012	53,625,237	\$ 1,219,929	\$ 23,293	\$ (3,244)	\$ (26,827)	\$ 1,213,151

See accompanying notes to consolidated financial statements

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

	Three Months Ended March 31,	
	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	\$ 6,471	\$ 241,574
Less: loss from discontinued operations		(81)
Net income from continuing operations	6,471	241,655
Adjustments to reconcile net income from continuing operations to net cash provided by operating activities:		
Depreciation and amortization	20,842	18,905
Equity income in joint ventures	(896)	(462)
Distributions received from joint ventures	1,800	1,764
Non-cash compensation expense	978	1,177
Amortization of deferred finance costs	1,165	1,267
Gain on asset sales		(255,947)
Change in operating assets and liabilities, net of business combinations:		
Accounts receivable, prepaid expenses and other	13,589	(4,876)
Accounts payable and accrued liabilities	(16,075)	(4,917)
Accounts payable and accounts receivable affiliates	426	(10,279)
Derivative accounts payable and receivable	14,447	15,440
Net cash provided by operating activities	42,747	3,727
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(81,167)	(18,333)
Capital contribution to joint ventures		(12,250)
Cash paid for business combination	(17,235)	
Net proceeds related to asset sales		411,753
Other	126	316
Net cash provided by (used in) continuing investing activities	(98,276)	381,486
Net cash used in discontinued investing activities		(81)
Net cash provided by (used in) investing activities	(98,276)	381,405
CASH FLOWS FROM FINANCING ACTIVITIES:		
Funds placed in escrow		(293,696)
Borrowings under credit facility	319,500	108,000
Repayments under credit facility	(231,500)	(178,000)
Principal payments on capital lease	(539)	(52)
Net proceeds from issuance of common limited partner units		468
Net distributions received from (paid to) non-controlling interest holders	38	(1,224)
Distributions paid to common limited partners, the General Partner and preferred limited partners	(31,737)	(20,554)
Other	(233)	(71)

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Net cash provided by (used in) financing activities	55,529	(385,129)
Net change in cash and cash equivalents		3
Cash and cash equivalents, beginning of period	168	164
Cash and cash equivalents, end of period	\$ 168	\$ 167

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, 2012

(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 and processing 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 regions 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, 2012, 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, 2012, the Partnership had 53,625,237 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, 2011 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, 2011. The results of operations for the three month period ended March 31, 2012 may not necessarily be indicative of the results of operations for the full year ending December 31, 2012. The Partnership has evaluated all events subsequent to the balance sheet date through the filing date of this Form 10-Q and has determined there are no subsequent events that require disclosure.

The Partnership has retrospectively adjusted its prior period consolidated financial statements to separately present derivative gain (loss) within derivative loss, net instead of combining these amounts in other income, net.

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, 2011.

Equity Method Investments

The Partnership's consolidated financial statements include its previously owned 49% non-controlling interest in Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), which was sold on February 17, 2011; and its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), which was acquired on May 11, 2011. The Partnership accounts for its investment in the

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joint ventures under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint ventures' net income (loss) as equity income (loss) on its consolidated statements of operations (see Note 3). 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 entry to equity income (loss) 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. Equity method investments are subject to impairment evaluation.

Intangible Assets

The Partnership amortizes intangible assets with finite useful lives over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership's customer contract intangible assets is based upon the approximate average length of customer contracts in existence and expected renewals at the date of acquisition. The estimated useful life for the Partnership's customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition, adjusted for management's estimate of whether these individual relationships will continue in excess or less than the average length (see Note 7).

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

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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 12), 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) from continuing operations and net income from discontinued operations 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,	
	2012	2011
Continuing operations:		
Net income	\$ 6,471	\$ 241,655
Income attributable to non-controlling interests	(1,536)	(1,187)
Preferred unit dividends		(240)
Net income attributable to common limited partners and the General Partner	4,935	240,228
General Partner's cash incentive distributions paid	1,397	
General Partner's ownership interest	71	4,829
Net income attributable to the General Partner's ownership interests	1,468	4,829
Net income attributable to common limited partners	3,467	235,399
Net income attributable to participating securities – phantom unit ⁽¹⁾	25	2,060
Net income utilized in the calculation of net income from continuing operations attributable to common limited partners per unit	\$ 3,442	\$ 233,339
Discontinued operations:		
Net loss	\$	\$ (81)
Net loss attributable to the General Partner's ownership interests		(2)
Net loss utilized in the calculation of net loss from discontinued operations attributable to common limited partners per unit	\$	\$ (79)

- (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).

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 12).

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

	Three Months Ended March 31,	
	2012	2011
Weighted average number of common limited partner units - basic	53,620	53,375
Add effect of participating securities - phantom units	393	471
Weighted average common limited partner units - diluted	54,013	53,846

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 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, at 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.

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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, 2012 and December 31, 2011 of \$64.3 million and \$68.6 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Recently Adopted Accounting Standards

In May 2011, the FASB issued Accounting Standards Update (ASU) 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs, which, among other changes, requires (1) additional disclosures for fair value measurements categorized within Level 2 and Level 3 of the fair value hierarchy; and (2) additional disclosures for items not measured at fair value in the Partnership's consolidated balance sheets but for which the fair value is required to be disclosed. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. The Partnership updated its disclosures to meet these requirements upon the adoption of this ASU on January 1, 2012 (see Note 9). The adoption had no material impact on the Partnership's financial position or results of operations.

In June 2011, the FASB issued ASU 2011-05, Comprehensive Income (Topic 220) Presentation of Comprehensive Income, which, among other changes, eliminates the option to present components of other comprehensive income as part of the statement of changes in equity. In December 2011, the FASB issued ASU 2011-12, Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05, which supersedes the requirements in ASU 2011-05 pertaining to how, when and where reclassifications out of accumulated other comprehensive income are presented on the face of the financial statements and reinstates the requirements for the presentation of reclassifications out of accumulated other comprehensive income that were in place before the issuance of ASU 2011-05. The amendments in these updates require all non-owner changes in equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The updates do 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, 2011. The Partnership began including consolidated statements of comprehensive income within its Form 10-Qs upon the adoption of these ASUs on January 1, 2012. The adoption had no material impact on the Partnership's financial position or results of operations.

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, which requires an entity to disclose additional information regarding offsetting arrangements for derivative instruments that are presented as net balances within its financial statements. Entities are required to implement the amendments for interim and annual reporting periods beginning after January 1, 2013 and apply them retrospectively for any period presented that begins before the date of initial application. The Partnership has elected to adopt these requirements early and has updated its disclosures to meet these requirements effective January 1, 2012 (see Note 8). The adoption had no material impact on the Partnership's financial position or results of operations.

Table of Contents**NOTE 3 INVESTMENT IN JOINT VENTURES***Laurel Mountain*

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain Midstream, LLC (Laurel Mountain), a Delaware limited liability company, to Atlas Energy Resources, LLC (Atlas Energy Resources), a wholly-owned subsidiary of Atlas Energy, Inc. (the Laurel Mountain Sale) for \$409.5 million in cash, including closing adjustments and net of expenses. Concurrently, Atlas Energy, Inc. became a wholly-owned subsidiary of Chevron Corporation (the Chevron Merger) and divested its interests in ATLS, resulting in the Laurel Mountain Sale being classified as a third party sale. The Partnership recognized a \$255.9 million gain on the sale during the three months ended March 31, 2011. Laurel Mountain is a joint venture, which owns and operates the Appalachia natural gas gathering system previously owned by the Partnership. Subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) hold the remaining 51% ownership interest. The Partnership utilized the proceeds from the sale to repay its indebtedness (see Note 10) and for general company purposes.

The Partnership recognized its 49% non-controlling ownership interest in Laurel Mountain as an investment in joint ventures on its consolidated balance sheets at fair value. The Partnership accounted for its ownership interest in Laurel Mountain under the equity method of accounting, with recognition of its ownership interest in the income of Laurel Mountain as equity income in joint ventures on its consolidated statements of operations. Since the Partnership accounted for its ownership as an equity investment, the Partnership did not reclassify the earnings or the gain on sale related to Laurel Mountain to discontinued operations upon the sale of its ownership interest.

West Texas LPG Pipeline Limited Partnership

On May 11, 2011, the Partnership acquired a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG) from Buckeye Partners, L.P. (NYSE: BPL) for \$85.0 million. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest. The Partnership recognizes its 20% interest in WTLPG as an investment in joint ventures on its consolidated balance sheets. The Partnership accounts for its ownership interest in WTLPG under the equity method of accounting, with recognition of its ownership interest in the income of WTLPG as equity income in joint ventures on its consolidated statements of operations. At the acquisition date, the carrying value of the 20% interest in WTLPG exceeded the Partnership's share of the underlying net assets of WTLPG by approximately \$49.9 million. The Partnership's analysis of this difference determined that it related to the fair value of property plant and equipment, which was in excess of book value. This excess will be depreciated over approximately a 38 year period. The allocation of the excess carrying value is based upon initial valuations and is subject to change.

The following table summarizes the components of equity income on the Partnership's statements of operations (in thousands):

	Three Months Ended March 31,	
	2012	2011
Equity income in Laurel Mountain	\$	\$ 462
Equity income in WTLPG	896	
Equity income in joint ventures	\$ 896	\$ 462

Table of Contents**NOTE 4 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 Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. 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, 2011 through December 31, 2011 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, 2011	May 13, 2011	0.40	21,400	439
June 30, 2011	August 12, 2011	0.47	25,184	967
September 30, 2011	November 14, 2011	0.54	28,953	1,844
December 31, 2011	February 14, 2012	0.55	29,489	2,031

On April 25, 2012, the Partnership declared a cash distribution of \$0.56 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2012. The \$32.2 million distribution, including \$2.2 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on May 15, 2012 to unitholders of record at the close of business on May 8, 2012.

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 10) (in thousands):

	March 31, 2012	December 31, 2011	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	\$ 1,696,077	\$ 1,615,015	2 40
Rights of way	168,810	161,191	20 40
Buildings	8,047	8,047	40
Furniture and equipment	9,477	9,392	3 7
Other	14,701	14,029	3 10
	1,897,112	1,807,674	
Less accumulated depreciation	(254,762)	(239,846)	
	\$ 1,642,350	\$ 1,567,828	

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 6.7% and 8.0% for the three months ended March 31, 2012 and 2011, respectively. The amount of interest capitalized was \$2.2 million and \$0.2 million for the three months ended March 31, 2012 and 2011, respectively.

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The Partnership recorded depreciation expense on property, plant and equipment, including amortization of capital lease arrangements (see Note 10), of \$15.0 million and \$13.1 million for the three months ended March 31, 2012 and 2011, respectively, on its consolidated statements of operations.

NOTE 6 OTHER ASSETS

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

	March 31, 2012	December 31, 2011
Deferred finance costs, net of accumulated amortization of \$20,030 and \$18,864 at March 31, 2012 and December 31, 2011, respectively	\$ 19,617	\$ 20,750
Security deposits	2,474	4,399
	\$ 22,091	\$ 25,149

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 10). Amortization expense of deferred finance costs was \$1.2 million and \$1.3 million for the three months ended March 31, 2012 and 2011, respectively, which is recorded within interest expense on the Partnership's consolidated statements of operations. Amortization expense related to deferred finance costs is estimated to be as follows for each of the next five calendar years: 2012 \$3.4 million; 2013 to 2014 \$4.6 million per year; 2015 \$4.3 million; 2016 \$0.9 million.

NOTE 7 INTANGIBLE ASSETS

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The Partnership completed an acquisition of a gas gathering system and related assets in February 2012. The Partnership accounted for the acquisition as a business combination and 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 and is subject to change. The following table reflects the components of intangible assets being amortized at March 31, 2012 and December 31, 2011 (in thousands):

	March 31, 2012	December 31, 2011	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	\$ 10,633	\$	14
Customer relationships	205,313	205,313	7 10
	215,946	205,313	
Accumulated amortization:			
Customer contracts	(63)		
Customer relationships	(107,813)	(102,037)	
	(107,876)	(102,037)	
Net carrying amount:			
Customer contracts	10,570		
Customer relationships	97,500	103,276	
Net carrying amount	\$ 108,070	\$ 103,276	

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The weighted-average amortization period for customer contracts and customer relationships is 14.0 years and 9.1 years, respectively. The Partnership recorded amortization expense on intangible

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assets of \$5.8 million for both the three months ended March 31, 2012 and 2011 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: 2012 to 2013 \$23.9 million per year; 2014 \$20.3 million; 2015 to 2016 \$15.3 million per year.

NOTE 8 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. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

The Partnership no longer applies hedge accounting for derivatives. Changes in fair value of derivatives are recognized immediately within derivative 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, will be reclassified to the Partnership's consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings. The Partnership will reclassify the \$3.2 million net loss in accumulated other comprehensive loss, within equity on the Partnership's consolidated balance sheets at March 31, 2012, to natural gas and liquids sales on the Partnership's consolidated statements of operations within the next twelve month period.

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 loss, net as unrealized gain (loss) on the Partnership's consolidated statements of operations. Premiums are reclassified to realized gain (loss) within derivative loss, net at the time the option expires or is exercised. The Partnership reflected net derivative assets on its consolidated balance sheets of \$3.2 million and \$16.5 million at March 31, 2012 and December 31, 2011, respectively.

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

	000000000	000000000	000000000
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Offsetting of Derivative Assets			
<u>As of December 31, 2011</u>			
Current portion of derivative assets	\$ 11,603	\$ (9,958)	\$ 1,645
Long-term portion of derivative assets	17,011	(2,197)	14,814
Total derivative assets, net	\$ 28,614	\$ (12,155)	\$ 16,459
<u>As of March 31, 2012</u>			
Current portion of derivative assets	\$ 10,080	\$ (10,080)	\$
Long-term portion of derivative assets	8,269	(3,469)	4,800
Total derivative assets, net	\$ 18,349	\$ (13,549)	\$ 4,800
	000000000	000000000	000000000
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
Offsetting of Derivative Liabilities			
<u>As of December 31, 2011</u>			
Current portion of derivative liabilities	\$ (9,958)	\$ 9,958	\$
Long-term portion of derivative liabilities	(2,197)	2,197	
Total derivative liabilities, net	\$ (12,155)	\$ 12,155	\$
<u>As of March 31, 2012</u>			
Current portion of derivative liabilities	\$ (11,722)	\$ 10,080	\$ (1,642)
Long-term portion of derivative liabilities	(3,469)	3,469	
Total derivative liabilities, net	\$ (15,191)	\$ 13,549	\$ (1,642)

The following table summarizes the Partnership's commodity derivatives as of March 31, 2012, (dollars and volumes in thousands):

Production Period	Commodity	Volumes ⁽¹⁾	Average Fixed Price (\$/Volume)	Fair Value ⁽²⁾ Asset/
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(Liability)

Fixed price swaps				
2012	Sold Natural gas	3,420	\$ 3.02	\$ 1,736
2012	Purchased NGLs	6,300	0.71	(1,240)
2012	Sold NGLs	30,366	1.36	(414)
2013	Sold NGLs	44,856	1.31	(1,723)
2012	Sold Crude oil	222	95.83	(1,912)
2013	Sold Crude oil	345	97.17	(2,291)
2014	Sold Crude oil	60	98.43	(104)
Total fixed price swaps				(5,948)

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Production Period	Commodity	Volumes ⁽¹⁾	Average Fixed Price (\$/Volume)	Fair Value ⁽²⁾ Asset/ (Liability)
Options				
<u>Purchased put options</u>				
2012	NGLs	42,210	1.55	3,870
2013	NGLs	38,556	1.94	6,190
2012	Crude oil	117	106.65	937
2013	Crude oil	282	100.10	2,852
<u>Purchased call options⁽³⁾</u>				
2012	Crude oil	135	125.20	183
<u>Sold call options⁽³⁾</u>				
2012	Crude oil	374	94.69	(4,926)
Total options				9,106
Total derivatives				\$ 3,158

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

(2) See Note 9 for discussion on fair value methodology.

(3) Calls purchased for 2012 represent offsetting positions for calls sold as part of costless collars. These offsetting positions were entered into to limit potential loss, which could be incurred if crude oil prices continued to rise.

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,	
	2012	2011
Derivatives previously designated as cash flow hedges		
Loss reclassified from accumulated other comprehensive loss into natural gas and liquids sales	\$ (1,146)	\$ (1,702)
Derivatives not designated as hedges		
Loss recognized in derivative loss, net		
Commodity contract realized ⁽¹⁾	\$ (763)	\$ (2,557)
Commodity contract unrealized ⁽²⁾	(11,272)	(19,088)
Derivative loss, net	\$ (12,035)	\$ (21,645)

(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.

NOTE 9 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,

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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.

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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 8). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership has a 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, 2012, 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 for isobutane, normal butane and natural gasoline are adjusted based upon the relationship between the prices for the product/locations quoted by the third party and the underlying product/locations utilized for the swap contracts, as determined by a regression model of the historical settlement prices for the different product/locations. The regression model is recalculated on a quarterly basis. This adjustment is an unobservable Level 3 input. The NGL fixed price swaps are over the counter instruments which are not actively traded in an open market. However, the prices for the underlying products and locations do have a direct correlation to the prices for the products and locations provided by the third party, which are based upon trading activity for the products and locations quoted. A change in the relationship between these prices would have a direct impact upon the unobservable adjustment utilized to calculate the fair value of the NGL fixed price swaps.

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The following table represents the Partnership's derivative assets and liabilities recorded at fair value as of March 31, 2012 and December 31, 2011 (in thousands):

	Level 1	Level 2	Level 3	Total
As of December 31, 2011				
Derivative assets, gross				
Commodity swaps	\$	\$ 1,270	\$ 1,836	\$ 3,106
Commodity options		7,229	18,279	25,508
Total derivative assets, gross		8,499	20,115	28,614
Derivative liabilities, gross				
Commodity swaps		(2,766)	(3,569)	(6,335)
Commodity options		(5,820)		(5,820)
Total derivative liabilities, gross		(8,586)	(3,569)	(12,155)
Total derivatives, fair value, net	\$	\$ (87)	\$ 16,546	\$ 16,459
As of March 31, 2012				
Derivative assets, gross				
Commodity swaps	\$	\$ 2,200	\$ 2,117	\$ 4,317
Commodity options		3,972	10,060	14,032
Total derivative assets, gross		6,172	12,177	18,349
Derivative liabilities, gross				
Commodity swaps		(4,771)	(5,494)	(10,265)
Commodity options		(4,926)		(4,926)
Total derivative liabilities, gross		(9,697)	(5,494)	(15,191)
Total derivatives, fair value, net	\$	\$ (3,525)	\$ 6,683	\$ 3,158

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, 2012 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance December 31, 2011	49,644	\$ (1,733)	92,610	\$ 18,279	\$ 16,546
New contracts ⁽¹⁾	42,084				
Cash settlements from unrealized gain (loss) ⁽²⁾⁽³⁾	(10,206)	(1,032)	(11,844)	696	(336)
Net change in unrealized gain (loss) ⁽²⁾		(612)		(6,529)	(7,141)
Deferred option premium recognition ⁽³⁾				(2,386)	(2,386)
Balance March 31, 2012	81,522	\$ (3,377)	80,766	\$ 10,060	\$ 6,683

- (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, 2012 and December 31, 2011 (in thousands):

	Gallons	Third Party Quotes ⁽¹⁾	Adjustments ⁽²⁾	Total Amount
As of December 31, 2011				
Ethane swaps	6,678	\$ 31	\$	\$ 31
Propane swaps	29,358	(1,322)		(1,322)
Isobutane swaps	2,646	(1,590)	570	(1,020)
Normal butane swaps	6,804	(1,074)	343	(731)
Natural gasoline swaps	4,158	1,824	(515)	1,309
Total NGL swaps December 31, 2011	49,644	\$ (2,131)	\$ 398	\$ (1,733)
As of March 31, 2012				
Ethane swaps	12,600	\$ 182	\$	\$ 182
Propane swaps	56,196	(646)		(646)
Isobutane swaps	3,276	(2,188)	714	(1,474)
Normal butane swaps	6,300	(1,917)	366	(1,551)
Natural gasoline swaps	3,150	216	(104)	112
Total NGL swaps March 31, 2012	81,522	\$ (4,353)	\$ 976	\$ (3,377)

- (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 swaps for the periods indicated (in thousands):

	Level 3 Fair Value Adjustments	Adjustment based upon Regression Coefficient		
		Lower 95%	Upper 95%	Average Coefficient
As of December 31, 2011				
Isobutane swaps	\$ 570	1.1239	1.1333	1.1286
Normal butane swaps	343	1.0311	1.0355	1.0333
Natural gasoline swaps	(515)	0.9351	0.9426	0.9389
Total NGL swaps December 31, 2011	\$ 398			
As of March 31, 2012				
Isobutane swaps	\$ 714	1.1192	1.1285	1.1239
Normal butane swaps	366	1.0312	1.0354	1.0333

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Natural gasoline swaps	(104)	0.9831	0.9859	0.9845
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Total NGL swaps	March 31, 2012	\$	976	
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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.

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The Partnership's current assets and liabilities on its consolidated balance sheets, other than the derivatives 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 8.75% Senior Notes is based upon the market approach and calculated using the yield of the 8.75% 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, 2012 and December 31, 2011, which consists principally of borrowings under the revolving credit facility and the 8.75% Senior Notes, were \$630.3 million and \$537.3 million, respectively, compared with the carrying amounts of \$613.3 million and \$524.1 million, respectively.

NOTE 10 DEBT

Total debt consists of the following (in thousands):

	March 31, 2012	December 31, 2011
Revolving credit facility	\$ 230,000	\$ 142,000
8.75% Senior notes due 2018	370,783	370,983
Capital lease obligations	12,542	11,157
Total debt	613,325	524,140
Less current maturities	(4,011)	(2,085)
Total long term debt	\$ 609,314	\$ 522,055

Cash payments for interest related to debt, net of capitalized interest, were a net credit of \$0.6 million for the three months ended March 31, 2012 and a net expense of \$0.6 million for the three months ended March 31, 2011.

Revolving Credit Facility

At March 31, 2012, the Partnership had a \$450.0 million senior secured revolving credit facility with a syndicate of banks that matures in December 2015. 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, 2012, was 2.8%. 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, 2012. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At March 31, 2012, the Partnership had \$219.9 million of remaining committed capacity under its revolving credit facility.

Borrowings under the revolving credit facility are secured by a lien on and security interest in all the Partnership's property and that of its subsidiaries, except for the assets owned by WestOK and WestTX joint ventures; and 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

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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, 2012, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At March 31, 2012, the Partnership had \$370.8 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes), including a net \$5.0 million unamortized premium. Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The 8.75% 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 8.75% Senior Notes are junior in right of payment to the Partnership's secured debt, including the Partnership's obligations under its revolving credit facility.

The indenture governing the 8.75% Senior Notes contains 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, 2012.

On March 7, 2011, the Partnership elected, pursuant to the indenture for the \$275.5 million principal amount then outstanding for 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes), to redeem all the 8.125% Senior Notes on April 8, 2011. The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. The Partnership placed \$293.7 million in escrow to redeem the \$275.5 million principal plus \$11.2 million premium and \$7.0 million accrued interest.

Capital Leases

During the three months ended March 31, 2012, the Partnership recorded \$2.0 million related to new capital lease agreements within property, plant and equipment and recorded an offsetting liability within long term debt on the Partnership's consolidated balance sheets. This amount was based upon the minimum payments required under the leases and the Partnership's incremental borrowing rate. The following is a summary of the leased property under capital leases as of March 31, 2012 and December 31, 2011, which are included within property, plant and equipment (see Note 5) (in thousands):

	March 31, 2012	December 31, 2011
Pipelines, processing and compression facilities	\$ 14,512	\$ 12,507
Less accumulated depreciation	(510)	(199)
	\$ 14,002	\$ 12,308

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Depreciation expense for leased properties was \$167 thousand and \$14 thousand for the three months ended March 31, 2012 and 2011, respectively, which is included within depreciation and amortization expense on the Partnership's consolidated statements of operations (see Note 5).

As of March 31, 2012, future minimum lease payments related to the capital leases are as follows (in thousands):

	Capital Lease Minimum Payments
2012	\$ 2,499
2013	10,879
2014	64
2015	
2016	
Thereafter	
Total minimum lease payments	13,442
Less amounts representing interest	(900)
Present value of minimum lease payments	12,542
Less current portion of capital lease obligations	(4,011)
Long-term capital lease obligations	\$ 8,531

NOTE 11 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 each of the three month periods ended March 31, 2012 and 2011, the Partnership paid \$2.5 million for transportation fees related to these contracts. The future fixed and determinable portion of the obligations as of March 31, 2012 was as follows: remainder of 2012 \$6.2 million; 2013 \$8.2 million; and 2014 \$6.1 million.

The Partnership had committed approximately \$68.1 million for the purchase of property, plant and equipment at March 31, 2012.

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 12 BENEFIT PLANS

Generally, 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. Except for phantom units awarded to non-employee managing board members of the

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General Partner and within the guidelines proscribed in each long term incentive plan, a committee (the LTIP Committee) appointed by the General Partner s managing board 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 LTIP Committee shall determine how the exercise price may be paid by the grantee. The LTIP Committee will determine the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant.

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 LTIP Committee. Under the LTIPs, the LTIP Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At March 31, 2012, the Partnership had 390,567 phantom units outstanding under the LTIPs, with 2,360,147 phantom units and unit options available for grant. Subsequent to March 31, 2012, the Partnership granted 692,000 phantom units under the 2010 LTIP. 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, 2012, 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 may automatically vest upon a change of control, as defined in the LTIPs. At March 31, 2012, there were 171,534 units outstanding under the LTIPs that will vest within the following twelve months. On February 17, 2011, the employment agreement with the Chief Executive Officer (CEO) of the General Partner was terminated in connection with the Chevron Merger (see Note 3) and 75,250 outstanding phantom units, which represent all outstanding phantom units held by the CEO, automatically vested and were issued.

All phantom units outstanding under the LTIPs at March 31, 2012 include DERs granted to the participants by the LTIP Committee. The amounts paid with respect to LTIP DERs were \$0.2 million, during each of the three month periods ended March 31, 2012 and 2011. These amounts were recorded as reductions of equity on the Partnership s consolidated balance sheets.

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

	Three Months Ended March 31, 2012		2011	
	Number of Units	Fair Value ⁽¹⁾	Number of Units	Fair Value ⁽¹⁾
Outstanding, beginning of period	394,489	\$ 21.63	490,886	\$ 11.75
Granted	4,132	36.29	5,730	30.63
Matured and issued ⁽²⁾	(8,054)	39.78	(81,900)	13.60
Outstanding, end of period ⁽³⁾⁽⁴⁾	390,567	\$ 21.41	414,716	\$ 11.65
Matured and not issued ⁽⁵⁾	4,125	\$ 44.51	4,500	\$ 44.51
Non-cash compensation expense recognized (in thousands)		\$ 978		\$ 1,174

- (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, 2012 and 2011 were \$0.3 million and \$2.4 million, respectively.
- (3) The aggregate intrinsic value for phantom unit awards outstanding at March 31, 2012 and 2011 was \$13.8 million and \$14.3 million, respectively.
- (4) There were 16,692 and 12,902 outstanding phantom unit awards at March 31, 2012 and 2011, 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 and 2011 was \$152 thousand and \$155 thousand, respectively.

At March 31, 2012, the Partnership had approximately \$4.5 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.1 years.

Partnership Unit Options. At March 31, 2012, there were no unit options outstanding. On February 17, 2011, the employment agreement with the CEO of the General Partner was terminated in connection with the Chevron Merger (see Note 3) and 50,000 outstanding unit options held by the CEO automatically vested. As of March 31, 2012, all unit options had been exercised.

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

	Three Months Ended March 31, 2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period		\$	75,000	\$ 6.24
Exercised ⁽¹⁾			(75,000)	6.24
Outstanding, end of period		\$		\$
Non-cash compensation expense recognized (in thousands)		\$		\$ 3

- (1) The intrinsic value for option unit awards exercised during the three months ended March 31, 2011 was \$1.8 million. Approximately \$0.5 million was received from exercise of unit option awards during the three months ended March 31, 2011.

Employee Incentive Compensation Plan and Agreement

At March 31, 2012, Atlas Pipeline Mid-Continent LLC, a wholly-owned subsidiary of the Partnership, had an incentive plan (the APLMC Plan) which allows for equity-indexed cash incentive awards to employees of the Partnership (the Participants). The APLMC Plan is administered by a committee appointed by the CEO of the General Partner. Under the APLMC Plan, cash bonus units (Bonus Unit) may be awarded to Participants at the discretion of the committee. A Bonus Unit entitles the employee to receive the cash equivalent of the then fair market value of a common limited partner

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unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vest ratably over a three year period from the date of grant and will automatically vest upon a change of control, death, or termination without cause, each as defined in the governing document. Vesting will terminate upon termination of employment with cause. At March 31, 2012, the Partnership had 25,500 outstanding Bonus Units, which will all vest within the following twelve months. The Partnership recognizes compensation expense related to these awards based upon the fair value, which is re-measured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized expense of \$36 thousand and \$505 thousand during the three months ended March 31, 2012 and 2011, respectively, which was recorded within general and administrative expense on its consolidated statements of operations. The Partnership had \$0.8 million at both March 31, 2012 and December 31, 2011 included within accrued liabilities on its consolidated balance sheets with regard to these awards, which represents their fair value as of those dates.

NOTE 13 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 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 \$0.9 million and \$0.4 million for the three months ended March 31, 2012 and 2011, 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, 2012 and 2011. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

On February 17, 2011, the Partnership completed the sale of its 49% interest in Laurel Mountain to Atlas Energy Resources for \$409.5 million, including closing adjustments and net of expenses (See Note 3).

NOTE 14 SEGMENT INFORMATION

On February 17, 2011, the Partnership sold its 49% interest in Laurel Mountain, which was reported as part of the Partnership's previous Appalachia segment (see Note 3). On May 11, 2011, the Partnership acquired a 20% interest in WTLPG (see Note 3). As a result of these two transactions, the Partnership realigned its reportable segments into two new segments: Gathering and Processing; and Pipeline Transportation (Pipeline). These reportable segments reflect the way the Partnership will manage its operations going forward. The Partnership has adjusted its segment presentation from the amounts previously presented to reflect the realignment of the segments.

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins, and which were formerly included within the previous Mid-Continent segment; (2) the natural gas gathering assets located in Tennessee, which were formerly included in the previous Appalachia segment; and (3) the revenues and gain on sale related to the

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Partnership's 49% interest in Laurel Mountain, which were formerly included in the previous Appalachia segment. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas.

The Pipeline segment consists of the equity income generated by the newly acquired interest in WTLP, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Pipeline revenues are primarily derived from transportation fees.

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

	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
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 ventures		896		896
Net income (loss)	\$ 37,492	\$ 813	\$ (31,834)	\$ 6,471

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	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
Three Months Ended March 31, 2011⁽²⁾:				
Revenue:				
Revenues third party ^(b)	\$ 280,088	\$	\$ (23,347)	\$ 256,741
Revenues affiliates	122			122
Total revenues	280,210		(23,347)	256,863
Costs and expenses:				
Operating costs and expenses	231,250			231,250
General and administrative ⁽¹⁾			9,017	9,017
Depreciation and amortization	18,905			18,905
Interest expense ⁽¹⁾			12,445	12,445
Total costs and expenses	250,155		21,462	271,617
Equity income in joint ventures	462			462
Gain on asset sale and other	255,947			255,947
Net income (loss) from continuing operations	286,464		(44,809)	241,655
Loss from discontinued operations			(81)	(81)
Net income (loss)	\$ 286,464	\$	\$ (44,890)	\$ 241,574

- (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.
- (2) Adjusted to reflect the realignment of the segments due to the sale of Laurel Mountain and the acquisition of WTLPG (see Note 3).

Capital Expenditures:	Three Months Ended March 31,	
	2012	2011 ⁽¹⁾
Gathering and processing	\$ 81,167	\$ 18,333
Pipeline		
	\$ 81,167	\$ 18,333

- (1) Adjusted to reflect the realignment of the segments due to the sale of Laurel Mountain and the acquisition of WTLPG (see Note 3).

Balance Sheet	March 31, 2012	December 31, 2011
Investment in joint ventures:		
Gathering and processing	\$	\$
Pipeline	85,975	86,879
	\$ 85,975	\$ 86,879

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Total assets:		
Gathering and processing	\$ 1,870,072	\$ 1,806,550
Pipeline	86,101	87,053
Corporate and other	24,745	37,209
	\$ 1,980,918	\$ 1,930,812

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

	Three Months Ended	
	March 31,	
	2012	2011
Natural gas and liquids sales:		
Natural gas	\$ 78,705	\$ 81,844
NGLs	188,694	167,794
Condensate	22,098	15,557
Other	(272)	1,114
 Total	 \$ 289,225	 \$ 266,309

NOTE 15 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership's 8.75% 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, 2012 and December 31, 2011 and for the three months ended March 31, 2012 and 2011 include the financial statements of 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. Under the terms of the 8.75% Senior Notes and the revolving credit facility, WestOK LLC and WestTX LLC 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, 2012 and December 31, 2011 and for the three months ended March 31, 2012 and 2011. 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):

Table of Contents**Balance Sheets**

March 31, 2012	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	\$	\$ 168	\$	\$	\$ 168
Accounts receivable affiliates	383,073	51,014		(434,087)	
Other current assets	754	23,925	94,074	(1,289)	117,464
Total current assets	383,827	75,107	94,074	(435,376)	117,632
Property, plant and equipment, net		284,904	1,357,446		1,642,350
Intangible assets, net			108,070		108,070
Investment in joint ventures		85,975			85,975
Long term portion of derivative assets		4,800			4,800
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,420,144	1,965,599		(3,385,743)	
Other assets, net	19,617	1,773	701		22,091
Total assets	\$ 1,823,588	\$ 2,418,158	\$ 3,413,219	\$ (5,674,047)	\$ 1,980,918
Liabilities and Equity					
Accounts payable affiliates	\$	\$	\$ 437,188	\$ (434,087)	\$ 3,101
Other current liabilities	9,540	25,724	113,960		149,224
Total current liabilities	9,540	25,724	551,148	(434,087)	152,325
Long-term debt, less current portion	600,783		8,531		609,314
Other long-term liability	115	13	6,000		6,128
Equity	1,213,150	2,392,421	2,847,540	(5,239,960)	1,213,151
Total liabilities and equity	\$ 1,823,588	\$ 2,418,158	\$ 3,413,219	\$ (5,674,047)	\$ 1,980,918
December 31, 2011					
Assets					
Cash and cash equivalents	\$	\$ 168	\$	\$	\$ 168
Accounts receivable affiliates	302,837	43,148		(345,985)	
Other current assets	151	30,486	103,414	(1,353)	132,698
Total current assets	302,988	73,802	103,414	(347,338)	132,866
Property, plant and equipment, net		275,514	1,292,314		1,567,828
Intangible assets, net			103,276		103,276
Investment in joint ventures		86,879			86,879
Long term portion of derivative assets		14,814			14,814
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,427,152	2,035,533		(3,462,685)	
Other assets, net	20,750	1,773	2,626		25,149
Total assets	\$ 1,750,890	\$ 2,488,315	\$ 3,354,558	\$ (5,662,951)	\$ 1,930,812

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Liabilities and Equity					
Accounts payable affiliates	\$	\$	\$ 348,660	\$ (345,985)	\$ 2,675
Other current liabilities	1,551	32,410	135,770		169,731
Total current liabilities	1,551	32,410	484,430	(345,985)	172,406
Long-term debt, less current portion	512,983		9,072		522,055
Other long-term liability	128	(5)			123
Equity	1,236,228	2,455,910	2,861,056	(5,316,966)	1,236,228
Total liabilities and equity	\$ 1,750,890	\$ 2,488,315	\$ 3,354,558	\$ (5,662,951)	\$ 1,930,812

Table of Contents**Statements of Operations**

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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	4,935	13,808	35,021	(47,293)	6,471
Income attributable to non-controlling interest			(1,536)		(1,536)
Net income 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	\$ 6,081	\$ 14,954	\$ 33,485	\$ (48,439)	\$ 6,081
Three Months Ended March 31, 2011					
Total revenues	\$	\$ 33,045	\$ 223,818	\$	\$ 256,863
Total costs and expenses	(11,095)	(64,903)	(195,619)		(271,617)
Equity income	251,672	28,148		(279,358)	462
Gain on asset sales and other		255,947			255,947
Income (loss) from continuing operations	240,577	252,237	28,199	(279,358)	241,655
Loss from discontinued operations		(81)			(81)
Net income	\$ 240,577	\$ 252,156	\$ 28,199	\$ (279,358)	\$ 241,574
Income attributable to non-controlling interest			(1,187)		(1,187)
Preferred unit dividends	(240)				(240)
Net income attributable to common limited partners and the General Partner	240,337	252,156	27,012	(279,358)	240,147
Other comprehensive income adjustment for realized losses on derivatives reclassified to net income	1,702	1,702		(1,702)	1,702
Comprehensive income	\$ 242,039	\$ 253,858	\$ 27,012	\$ (281,060)	\$ 241,849

Table of Contents**Statements of Cash Flows**

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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
Three Months Ended March 31, 2011					
Net cash provided by (used in):					
Operating activities	\$ 74,908	\$ (5,551)	\$ 45,901	\$ (111,531)	\$ 3,727
Continuing investing activities	310,169	589,527	(15,298)	(502,912)	381,486
Discontinued investing activities		(81)			(81)
Investing activities	310,169	589,446	(15,298)	(502,912)	381,405
Financing activities	(385,077)	(583,892)	(30,603)	614,443	(385,129)
Net change in cash and cash equivalents					
Cash and cash equivalents, beginning of period		164			164
Cash and cash equivalents, end of period	\$	\$ 167	\$	\$	\$ 167

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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, 2011. 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, 2011.

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 and processing services in the Anadarko 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.

Due to the sale of our 49% non-controlling interest in Laurel Mountain Midstream, LLC (*Laurel Mountain*), a Delaware limited liability company, and our acquisition of a 20% interest in West Texas LPG Pipeline Limited Partnership (*WTLPG*) in 2011, we realigned the management of our business in the midstream segment of the natural gas industry into two new reportable segments: Gathering and Processing; and Pipeline Transportation.

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins, and which were formerly included within the previous Mid-Continent segment; (2) the natural gas gathering assets located in Tennessee, which were formerly included in the previous Appalachia segment; and (3) the revenues and gain on sale related to our 49% interest in Laurel Mountain, which were formerly included in the previous Appalachia segment. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering and processing of natural gas.

Our Gathering and Processing operations, own, have interests in and operate seven natural gas processing plants with aggregate capacity of approximately 610 MMCFD, which are connected to approximately 9,000 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas. In addition, we own and operate approximately 100 miles of active natural gas gathering systems located in Tennessee. Our gathering systems gather gas from wells and central delivery points and deliver to natural gas processing plants, as well as third-party pipelines.

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Our Pipeline Transportation operations consist of 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. 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

In February 2012, we acquired a gas gathering system and related assets, within our WestOK system, for an initial net purchase price of \$19.0 million. We 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. In connection with this acquisition, we received assignment of gas purchase agreements for gas currently gathered on the acquired system. We accounted for the acquisition as a business combination.

How We Evaluate Our Operations

Our principal revenue is generated from the gathering and 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 and NGLs 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 and process, 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 and process and the NGLs and condensate we recover and sell, which is a function of the relevant supply and demand in the mid-continent, mid-Atlantic 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 plants.

Revenue consists of the sale of natural gas and NGLs and the fees earned from our gathering and processing 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 and NGLs 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).

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

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

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

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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 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.

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.

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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, 2012 and 2011 (in thousands):

RECONCILIATION OF GROSS MARGIN

	Three Months Ended March 31,	
	2012	2011⁽¹⁾
Net income	\$ 6,471	\$ 241,574
Adjustments:		
Derivative loss, net ⁽¹⁾	12,035	21,645
Other income, net ⁽¹⁾	(2,415)	(2,789)
Operating expenses ⁽²⁾	14,111	12,958
General and administrative expense ⁽³⁾	9,945	9,017
Depreciation and amortization	20,842	18,905
Interest	8,708	12,445
Equity income in joint ventures	(896)	(462)
Gain on asset sale ⁽⁴⁾		(255,866)
Non-cash linefill (gain) loss ⁽⁵⁾	272	(1,114)
Gross margin	\$ 69,073	\$ 56,313

RECONCILIATION OF EBITDA, ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW

Net income	\$ 6,471	\$ 241,574
Adjustments:		
Income attributable to non-controlling interests ⁽⁶⁾	(1,536)	(1,187)
Interest expense	8,708	12,445
Depreciation and amortization	20,842	18,905
EBITDA	34,485	271,737
Adjustments:		
Equity income in joint ventures	(896)	(462)
Distributions from joint ventures	1,800	1,764
Gain on asset sales and other		(255,866)
Non-cash loss on derivatives	10,696	18,360
Premium expense on derivative instruments	3,752	3,005
Non-cash compensation	978	1,177
Non-cash line fill (gain) loss ⁽⁵⁾	272	(1,114)
Adjusted EBITDA	51,087	38,601
Adjustments:		
Interest expense	(8,708)	(12,445)
Amortization of deferred finance costs	1,165	1,267
Preferred dividend obligation		(240)
Proceeds remaining from asset sale ⁽⁷⁾		5,850
Premium expense on derivative instruments	(3,752)	(3,005)
Other costs	(34)	
Maintenance capital	(4,510)	(3,260)
Distributable Cash Flow	\$ 35,248	\$ 26,768

- (1) Adjusted to separately present derivative gain (losses) instead of combining these amounts in other income, net.
- (2) Operating expenses include plant operating expenses; transportation and compression expenses; and other costs.
- (3) General and administrative includes compensation reimbursement to affiliates.
- (4) Represents the gain on sale of Laurel Mountain and an adjustment to the gain on sale of our Elk City system.
- (5) Represents the non-cash impact of commodity price movements on pipeline linefill.
- (6) Represents Anadarko's non-controlling interest in the operating results of the WestOK and WestTX systems.
- (7) Net proceeds remaining from the sale of Laurel Mountain after the repayment of the amount outstanding on our revolving credit facility, redemption of our 8.125% Senior Notes due 2015 and purchase of certain 8.75% Senior Notes due 2018.

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The following table illustrates selected pricing before the effect of derivatives and volumetric information related to our Gathering and Processing segment for the periods indicated:

	Three Months Ended March 31,		
	2012	2011	Percent Change
Pricing:			
Weighted Average Market Prices:			
NGL price per gallon Conway hub	\$ 0.93	\$ 1.08	(13.9)%
NGL price per gallon Mt. Belvieu hub	1.18	1.21	(2.5)%
Natural gas sales (\$/Mcf):			
Velma	2.55	3.98	(35.9)%
WestOK	2.56	3.94	(35.0)%
WestTX	2.51	3.92	(36.0)%
Weighted Average	2.54	3.94	(35.5)%
NGL sales (\$/gallon):			
Velma	0.93	1.03	(9.7)%
WestOK	0.91	1.06	(14.2)%
WestTX	1.17	1.18	(0.8)%
Weighted Average	1.03	1.10	(6.4)%
Condensate sales (\$/barrel):			
Velma	102.22	92.24	10.8%
WestOK	93.95	84.72	10.9%
WestTX	101.38	89.80	12.9%
Weighted Average	97.44	88.29	10.4%
Operating data:			
Velma system:			
Gathered gas volume (MCFD)	129,223	90,614	42.6%
Processed gas volume (MCFD)	122,904	85,158	44.3%
Residue gas volume (MCFD)	100,335	69,714	43.9%
NGL volume (BPD)	13,643	10,071	35.5%
Condensate volume (BPD)	564	530	6.4%
WestOK system:			
Gathered gas volume (MCFD)	295,198	242,965	21.5%
Processed gas volume (MCFD)	279,305	228,865	22.0%
Residue gas volume (MCFD)	251,940	198,640	26.8%
NGL volume (BPD)	14,062	13,591	3.5%
Condensate volume (BPD)	1,405	859	63.6%
WestTX system ⁽¹⁾ :			
Gathered gas volume (MCFD)	246,339	185,918	32.5%
Processed gas volume (MCFD)	230,504	172,817	33.4%
Residue gas volume (MCFD)	160,022	115,917	38.0%
NGL volume (BPD)	33,101	27,476	20.5%
Condensate volume (BPD)	939	1,024	(8.3)%
Tennessee system:			
Average throughput volumes (MCFD)	8,225	8,079	1.8%
WTLPG system ⁽¹⁾ :			
Average NGL volumes (BPD)	242,318	223,217	8.6%

- (1) Operating data for WestTX and WTLPG represent 100% of the operating activity for the respective systems.

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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, 2012 and 2011 (in thousands):

	Three Months Ended March 31,			
	2012	2011 ⁽¹⁾	Variance	Percent Change
<i>Gross margin</i> ⁽²⁾				
Natural gas and liquids sales	\$ 289,225	\$ 266,309	\$ 22,916	8.6%
Transportation, processing and other fees	12,681	9,410	3,271	34.8%
Less: non-cash line fill gain (loss) ⁽³⁾	(272)	1,114	(1,386)	(124.4)%
Less: natural gas and liquids cost of sales	233,105	218,292	14,813	6.8%
 Gross margin	 69,073	 56,313	 12,760	 22.7%
<i>Expenses:</i>				
Operating expenses	14,111	12,958	1,153	8.9%
General and administrative ⁽⁴⁾	9,945	9,017	928	10.3%
Depreciation and amortization	20,842	18,905	1,937	10.2%
Interest expense	8,708	12,445	(3,737)	(30.0)%
 Total expenses	 53,606	 53,325	 281	 0.5%
<i>Other income items:</i>				
Derivative loss, net ⁽¹⁾	(12,035)	(21,645)	9,610	44.4%
Other income, net ⁽¹⁾	2,415	2,789	(374)	(13.4)%
Non-cash line fill gain (loss) ⁽³⁾	(272)	1,114	(1,386)	(124.4)%
Equity income in joint ventures	896	462	434	93.9%
Gain on asset sales and other ⁽⁵⁾		255,866	(255,866)	(100.0)%
Income attributable to non-controlling interests ⁽⁶⁾	(1,536)	(1,187)	(349)	(29.4)%
Preferred unit dividends		(240)	240	100.0%
 Net income attributable to common limited partners and General Partner	 \$ 4,935	 \$ 240,147	 \$ (235,212)	 (97.9)%
 <i>Non-GAAP financial data:</i>				
EBITDA ⁽²⁾	\$ 34,485	\$ 271,737	\$ (237,252)	(87.3)%
Adjusted EBITDA ⁽²⁾	51,087	38,601	12,486	32.3%
Distributable cash flow ⁽²⁾	35,248	26,768	8,480	31.7%

(1) Adjusted to separately present derivative gain (losses) instead of combining these amounts in other income, net.

(2) 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](#)).

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

(4) General and administrative also includes any compensation reimbursement to affiliates.

(5) Represents the gain on sale Laurel Mountain and an adjustment to the gain on sale of our Elk City system.

(6) Represents Anadarko's non-controlling interest in the operating results of the WestOK and WestTX systems.

Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

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, 2012 increased primarily due to higher production volumes partially offset by lower natural gas and NGL sales prices.

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Volumes on the Velma system increased for the three months ended March 31, 2012 when compared to the prior year period primarily due to increased production gathered on the Madill-to-Velma

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gas gathering pipeline. Volumes on the WestOK system increased for the three months ended March 31, 2012 compared to the prior year primarily due to increased production gathered on the previously expanded gathering systems. WestTX system gathering and processing volumes for the three months ended March 31, 2012 increased when 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, 2012 increased primarily due to increased processing fee revenue on the WestOK and Velma systems related to the increased volumes gathered on the systems.

Expenses:

Operating expenses, comprised of plant operating expenses and transportation and compression expenses, for the three months ended March 31, 2012 increased 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, 2012 mainly due to increased salary, wages and benefits and an increase in the allocation from our General Partner for compensation and benefits related to its employees who perform services for us.

Depreciation and amortization expense for the three months ended March 31, 2012 increased primarily due to expansion capital expenditures incurred subsequent to March 31, 2011.

Interest expense for the three months ended March 31, 2012 decreased primarily due to a \$5.6 million decrease in interest expense associated with the 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes) and a \$2.0 million increase in capitalized interest, partially offset by a \$2.9 million increase in interest expense associated with the 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and a \$1.0 million increase in interest associated with the revolving credit facility. The lower interest expense on our 8.125% Senior Notes is due to the redemption of the 8.125% Senior Notes in April 2011 with proceeds from the sale of our 49% non-controlling interest in Laurel Mountain. The increased capitalized interest is due to the increased capital expenditures in the current period (see *Capital Requirements*). The increased interest on the 8.75% Senior Notes is due to the issuance of additional 8.75% Senior Notes in November 2011. The increased interest on the revolving credit facility is due to additional borrowings in the current period to cover the current capital expenditures.

Other income items:

Derivative loss, net had a favorable variance for the three months ended March 31, 2012 mainly due to a \$7.8 million reduced loss on the fair value revaluation of derivatives in the current period compared to the prior year period combined with \$1.8 million lower realized settlements in the current period. The reduced loss on the fair value revaluation was a result of a decrease in NGL prices during the current period compared to an increase in NGL prices during the prior year period combined with fewer outstanding sold crude call options in the current period. The reduced cash settlements were primarily due to a favorable variance in NGL swap settlements as a result of higher fixed prices for the current period derivatives compared to the prior year period. 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*.

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Other income, net for the three months ended March 31, 2012 decreased compared to the prior year period primarily due to lower interest income, partially due to the December 2011 settlement of a note receivable from The Williams Companies, Inc. (NYSE: WMB) related to our 49% non-controlling ownership interest in Laurel Mountain, which we sold in February 2011.

Non-cash line fill gain (loss) had an unfavorable variance for the three months ended March 31, 2012 compared to the prior year period primarily due to a loss recognized on the revaluation of line fill due to decreased NGL prices compared to a gain recognized on the revaluation of line fill during the three months ended March 31, 2011 due to increased NGL prices.

Equity income in joint ventures increased for the three months ended March 31, 2012, primarily due to \$0.9 million in equity earnings generated in the current period from our 20% ownership interest in WTPLG, which was purchased in May 2011, offset by \$0.5 million in equity earnings from our 49% noncontrolling interest in Laurel Mountain, which was sold in February 2011.

Gain on asset sales and other for the three months ended March 31, 2011 includes amounts associated with the sale of our 49% interest in Laurel Mountain on February 17, 2011.

Income attributable to non-controlling interests increased primarily due to higher net income for the WestOK and WestTX joint ventures, which were formed to accomplish our acquisition of control of the systems. The increase in net income of the joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher volumes. The non-controlling interest expense represents Anadarko Petroleum Corporation's interest in the net income of the WestOK and WestOK joint ventures.

Preferred unit dividends for the three months ended March 31, 2011 represent dividends paid on the then outstanding 8,000 units of 12% Cumulative Class C Preferred Units, which were redeemed in 2011.

Non-GAAP financial data:

EBITDA was lower for the three months ended March 31, 2012 compared to the prior year period mainly due to the gain on sale of assets recognized during the three months ended March 31, 2011, as discussed above in Other income items .

Adjusted EBITDA and Distributable Cash Flow had favorable variances for the three months ended March 31, 2012 compared to the prior year period mainly due to the favorable gross margin variance, as discussed above in Gross margin .

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.

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At March 31, 2012, we had \$230.0 million outstanding borrowings under our \$450.0 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 \$219.9 million of remaining committed capacity under the revolving credit facility, (see [Revolving Credit Facility](#)). We were in compliance with the credit facility's covenants at March 31, 2012. We had a working capital deficit of \$34.7 million at March 31, 2012 compared with a \$39.5 million working capital deficit at December 31, 2011. 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 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.

Cash Flows Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2011

The following table details the cash flow changes between the three months ended March 31, 2012 and 2011 (in thousands):

	Three Months Ended March 31,		Variance	Percent Change
	2012	2011		
Net cash provided by (used in):				
Operating activities	\$ 42,747	\$ 3,727	\$ 39,020	1,047.0%
Investing activities	(98,276)	381,405	(479,681)	(125.8)%
Financing activities	55,529	(385,129)	440,658	114.4%
Net change in cash and cash equivalents	\$	\$ 3	\$ (3)	(100.0)%

Net cash provided by operating activities for the three months ended March 31, 2012 increased compared to the prior year period due to a \$21.0 million increase in net earnings from continuing operations excluding non-cash charges and an \$18.0 million favorable variance in the change in working capital. The increase in net earnings from continuing operations excluding non-cash charges is primarily due to increased revenues from the sale of natural gas and NGLs (see [Results of Operations](#)). The favorable variance in the change in working capital is mainly a result of decreased outstanding accounts receivables during the three months ended March 31, 2012.

Net cash provided by investing activities for the three months ended March 31, 2012 decreased compared to the prior year period mainly due to net proceeds of \$411.8 million received from the sale of Laurel Mountain in the prior period, a \$62.8 million increase in capital expenditures in the current year period compared to the prior year period (see further discussion of capital expenditures under [Capital Requirements](#)) and \$17.2 million cash paid for acquisition of assets in the current period, partially offset by \$12.3 million cash paid in capital contributions to Laurel Mountain in the prior year period.

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Net cash provided by financing activities for the three months ended March 31, 2012 increased compared to the prior year period mainly due to \$293.7 million used in the prior period to place funds in escrow for the repayment of the 8.125% Senior Notes, \$88.0 million provided by additional borrowings on our revolving credit facility in the current period and \$70.0 million used in the prior period to reduce outstanding borrowings on the revolving credit facility.

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,	
	2012	2011
Maintenance capital expenditures	\$ 4,510	\$ 3,260
Expansion capital expenditures	76,657	15,073
Total	\$ 81,167	\$ 18,333

Expansion capital expenditures increased for the three months ended March 31, 2012 primarily due to the current major processing facility expansions, compressor upgrades and pipeline projects. The increase in maintenance capital expenditures for the three months ended March 31, 2012 when compared with the prior year period was due to fluctuations in the timing of scheduled maintenance activity. As of March 31, 2012, we had approved additional expenditures of approximately \$168.6 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately \$68.1 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.

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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 \$1.4 million were paid during the three months ended March 31, 2012. No incentive distributions were paid during the three months ended March 31, 2011.

Off Balance Sheet Arrangements

As of March 31, 2012, 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.

Revolving Credit Facility

At March 31, 2012, we had a \$450.0 million senior secured revolving credit facility with a syndicate of banks, which matures in December 2015. 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, 2012, was 2.8%. 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, 2012. 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 and WestTX joint ventures. 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, 2012, we were in compliance with all covenants under the revolving credit facility.

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Senior Notes

At March 31, 2012, we had \$370.8 million principal amount outstanding of 8.75% Senior Notes, including a net \$5.0 million unamortized premium. Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The 8.75% 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 8.75% Senior Notes are junior in right of payment to our secured debt, including our obligations under our revolving credit facility.

The indenture governing the 8.75% Senior Notes contains 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, 2012.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions 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, 2011.

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Description	Judgments and Uncertainties	Effect if
		Actual Results Differ from
		Estimates and Assumptions
<i>Acquisitions Purchase Price Allocation</i>		
We allocate the purchase price of an acquired business to its identifiable assets and liabilities based on estimated fair values. The excess of the purchase price over the amount allocated to the assets and liabilities is recorded as goodwill. For significant acquisitions, we engage outside appraisal firms to assist in the fair value determination of identifiable intangible assets such as customer relationships, customer contracts and any other significant assets or liabilities. We adjust the preliminary purchase price allocation, as necessary, after the acquisition closing date through the end of the measurement period of up to one year as we finalize valuations for the assets acquired and liabilities assumed.	Purchase price allocation methodology requires management to make assumptions and apply judgment to estimate the fair value of acquired assets and liabilities. Management estimates the fair value of assets and liabilities primarily using a market approach, income approach, or cost approach, as appropriate. Key inputs into the fair value determinations include estimates and assumptions related to future volumes, commodity prices, operating costs, replacement costs and construction costs, as well as an estimate of the expected term and profits of the related customer contracts.	If estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets and liabilities significantly differ from assumptions made, the allocation of purchase price between goodwill, intangibles and property plant and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangibles or goodwill are not achieved, impairments could arise.
<i>Recently Adopted Accounting Standards</i>		

See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Recently Adopted Accounting Standards for information regarding adoption of recent 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, 2012. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

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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, 2012, we had a \$450.0 million senior secured revolving credit facility with \$230.0 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 2.8% at March 31, 2012. 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 \$2.3 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 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 7 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 4, 2012, were \$1.09 per gallon, \$2.74 per million BTU and \$103.22 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended March 31, 2013 by approximately \$9.9 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.

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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, 2012, our disclosure controls and procedures were effective at the reasonable assurance level.

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

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

There have been no material changes in our risk factors from those disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2011.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Purchase and Sale Agreement, by and among Atlas Pipeline Partners, L.P., APL Laurel Mountain, LLC, Atlas Energy, Inc., and Atlas Energy Resources, LLC, dated November 8, 2010 ⁽¹³⁾
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⁾
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 ⁽²⁵⁾
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⁾
10.4	Long-Term Incentive Plan ⁽²¹⁾
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⁾

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- 10.8 Form of Grant of Phantom Units to Non-Employee Managers⁽¹¹⁾
- 10.9 Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan⁽¹⁰⁾
- 10.10 Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement⁽¹⁰⁾
- 10.11 Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010⁽¹³⁾
- 10.12 Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010⁽²⁰⁾
- 10.13 Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010⁽²⁰⁾
- 10.14 Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011⁽²⁴⁾
- 10.17 Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011⁽²⁴⁾
- 10.18 Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011⁽²¹⁾

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Exhibit No.	Description
10.19	Purchase Agreement dated November 16, 2011 by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Partners GP, LLC, Atlas Pipeline Operating Partnership, L.P. and the initial purchasers named therein ⁽¹⁹⁾
10.20	Registration Rights Agreement dated November 21, 2011 ⁽¹⁹⁾
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 ⁽²⁶⁾
101.SCH	XBRL Schema Document ⁽²⁶⁾
101.CAL	XBRL Calculation Linkbase Document ⁽²⁶⁾
101.LAB	XBRL Label Linkbase Document ⁽²⁶⁾
101.PRE	XBRL Presentation Linkbase Document ⁽²⁶⁾
101.DEF	XBRL Definition Linkbase Document ⁽²⁶⁾

- (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 annual report on Form 10-K filed for the year ended December 31, 2009.
- (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 current report on Form 8-K filed on November 21, 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 annual report on Form 10-K filed for the year ended December 31, 2011.
- (26) 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.

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SIGNATURES

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

ATLAS PIPELINE PARTNERS, L.P.

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

Date: May 7, 2012

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

Date: May 7, 2012

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