

ATLAS PIPELINE PARTNERS LP
Form 10-Q
November 05, 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 September 30, 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	
Pittsburgh, Pennsylvania (Address of principal executive office)	15275-1011 (Zip code)
Registrant's telephone number, including area code :(877) 950-7473	

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

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

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

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

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

The number of common units of the registrant outstanding on November 1, 2012 was 53,756,925.

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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, which 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, which 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)

	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 165	\$ 168
Accounts receivable	108,270	115,412
Current portion of derivative assets	26,220	1,645
Prepaid expenses and other	10,683	15,641
Total current assets	145,338	132,866
Property, plant and equipment, net	1,809,091	1,567,828
Intangible assets, net	105,496	103,276
Investment in joint ventures	85,714	86,879
Long-term portion of derivative assets	17,195	14,814
Other assets, net	29,007	25,149
Total assets	\$ 2,191,841	\$ 1,930,812
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	\$ 11,103	\$ 2,085
Accounts payable affiliates	2,539	2,675
Accounts payable	59,316	54,644
Accrued liabilities	31,248	23,282
Accrued interest payable	9,723	1,624
Accrued producer liabilities	71,884	88,096
Total current liabilities	185,813	172,406
Long-term debt, less current portion	775,510	522,055
Other long-term liability	6,458	123
Commitments and contingencies		
Equity:		
Common limited partners interests	1,225,974	1,245,163
General Partner s interest	23,257	23,856
Accumulated other comprehensive loss	(1,057)	(4,390)
Total partners capital	1,248,174	1,264,629
Non-controlling interest	(24,114)	(28,401)

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Total equity	1,224,060	1,236,228
Total liabilities and equity	\$ 2,191,841	\$ 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenue:				
Natural gas and liquids sales	\$ 274,618	\$ 341,498	\$ 802,644	\$ 937,975
Transportation, processing and other fees third parties	19,116	11,612	46,474	31,280
Transportation, processing and other fees affiliates	156	79	357	256
Derivative gain (loss), net	(18,907)	23,760	36,905	8,952
Other income, net	2,585	2,831	7,588	8,365
Total revenues	277,568	379,780	893,968	986,828
Costs and expenses:				
Natural gas and liquids cost of sales	224,778	282,391	652,986	774,859
Plant operating	15,180	14,085	43,661	40,240
Transportation and compression	520	268	996	603
General and administrative	11,248	8,686	29,888	25,477
Compensation reimbursement affiliates	875	463	2,625	1,344
Other costs	(108)	8	(303)	583
Depreciation and amortization	23,161	19,471	65,715	57,499
Interest	9,692	5,935	27,669	24,525
Total costs and expenses	285,346	331,307	823,237	925,130
Equity income in joint ventures	1,422	1,785	4,235	2,934
Gain on asset sales and other				255,674
Loss on early extinguishment of debt				(19,574)
Income (loss) from continuing operations	(6,356)	50,258	74,966	300,732
Loss on sale of discontinued operations				(81)
Net income (loss)	(6,356)	50,258	74,966	300,651
Income attributable to non-controlling interests	(1,511)	(1,760)	(4,108)	(4,492)
Preferred unit dividends				(389)
Net income (loss) attributable to common limited partners and the General Partner	\$ (7,867)	\$ 48,498	\$ 70,858	\$ 295,770

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

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Allocation of net income (loss) attributable to:				
Common limited partner interest:				
Continuing operations	\$ (9,249)	\$ 47,091	\$ 64,988	\$ 289,472
Discontinued operations				(79)
	(9,249)	47,091	64,988	289,393
General Partner interest:				
Continuing operations	1,382	1,407	5,870	6,379
Discontinued operations				(2)
	1,382	1,407	5,870	6,377
Net income (loss) attributable to:				
Continuing operations	(7,867)	48,498	70,858	295,851
Discontinued operations				(81)
	\$ (7,867)	\$ 48,498	\$ 70,858	\$ 295,770
Net income (loss) attributable to common limited partners per unit:				
Basic	\$ (0.17)	\$ 0.87	\$ 1.19	\$ 5.37
Weighted average common limited partner units (basic)	53,736	53,588	53,668	53,494
Diluted	\$ (0.17)	\$ 0.87	\$ 1.19	\$ 5.37
Weighted average common limited partner units (diluted)	53,736	54,012	54,409	53,923

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income (loss)	\$ (6,356)	\$ 50,258	\$ 74,966	\$ 300,651
Income attributable to non-controlling interests	(1,511)	(1,760)	(4,108)	(4,492)
Preferred unit dividends				(389)
Net income (loss) attributable to common limited partners and the General Partner	(7,867)	48,498	70,858	295,770
Other comprehensive income:				
Adjustment for realized losses on cash flow hedges reclassified to net income (loss)	1,079	1,714	3,333	5,118
Comprehensive income (loss)	\$ (6,788)	\$ 50,212	\$ 74,191	\$ 300,888

See accompanying notes to consolidated financial statements

Table of Contents**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES****CONSOLIDATED STATEMENT OF EQUITY****FOR THE NINE MONTHS ENDED SEPTEMBER 30, 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	161,016	92				92
Equity based compensation expense		7,401				7,401
Purchase and retirement of treasury stock	(24,052)	(695)				(695)
Distributions paid		(90,975)	(6,469)			(97,444)
Distributions received from non-controlling interests					179	179
Other comprehensive income				3,333		3,333
Net income		64,988	5,870		4,108	74,966
Balance at September 30, 2012	53,754,147	\$ 1,225,974	\$ 23,257	\$ (1,057)	\$ (24,114)	\$ 1,224,060

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)**

	Nine Months Ended September 30,	
	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	\$ 74,966	\$ 300,651
Add: loss from discontinued operations		(81)
Net income from continuing operations	74,966	300,732
Adjustments to reconcile net income from continuing operations to net cash provided by operating activities:		
Depreciation and amortization	65,715	57,499
Equity income in joint ventures	(4,235)	(2,934)
Distributions received from joint ventures	5,400	2,548
Non-cash compensation expense	7,537	2,507
Amortization of deferred finance costs	3,356	3,354
Gain on asset sales		(255,674)
Loss on early extinguishment of debt		19,574
Change in operating assets and liabilities, net of business combinations:		
Accounts receivable, prepaid expenses and other	12,100	(18,950)
Accounts payable and accrued liabilities	(15,557)	25,497
Accounts payable and accounts receivable affiliates	(136)	(9,604)
Derivative accounts payable and receivable	(23,623)	(43,891)
Net cash provided by operating activities	125,523	80,658
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(242,412)	(148,144)
Capital contribution to joint ventures		(12,250)
Cash paid for business combinations	(36,689)	(85,000)
Net proceeds related to asset sales		411,480
Other	376	(11)
Net cash provided by (used in) continuing investing activities	(278,725)	166,075
Net cash used in discontinued investing activities		(81)
Net cash provided by (used in) investing activities	(278,725)	165,994
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	676,500	995,500
Repayments under credit facility	(738,500)	(867,000)
Net proceeds from issuance of long-term debt	319,100	
Repayment of debt		(279,557)
Payment of premium on early retirement of debt		(14,342)
Payments of deferred financing costs associated with credit facility	(3,490)	
Principal payments on capital lease	(1,852)	(452)
Net proceeds from issuance of common limited partner units		468
Purchase and retirement of treasury units	(695)	(984)

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Redemption of preferred limited partner units	(8,000)	
Net distributions received from (paid to) non-controlling interest holders	179	(1,820)
Distributions paid to common limited partners, the General Partner and preferred limited partners	(97,444)	(69,302)
Other	(599)	(1,160)
Net cash provided by (used in) financing activities	153,199	(246,649)
Net change in cash and cash equivalents	(3)	3
Cash and cash equivalents, beginning of period	168	164
Cash and cash equivalents, end of period	\$ 165	\$ 167

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

SEPTEMBER 30, 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 region of the United States; and the transportation of NGLs in the southwestern region of the United States. The Partnership's operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. At September 30, 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 September 30, 2012, the Partnership had 53,754,147 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 nine month period ended September 30, 2012 may not necessarily be indicative of the results of operations for the full year ending December 31, 2012.

The Partnership has retrospectively adjusted its prior period consolidated financial statements to separately present derivative gain (loss) within derivative gain (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) until it was sold on February 17, 2011; and its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG) after its acquisition on May 11, 2011. The Partnership accounts for its investment in the joint ventures under the equity method of accounting. Under this method, the Partnership records its

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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 reduction 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. No goodwill was recorded on the acquisition of Laurel Mountain or WTLPG. Equity method investments are subject to impairment evaluation.

NGL Linefill

The Partnership had \$6.7 million and \$11.5 million of NGL linefill at September 30, 2012 and December 31, 2011, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties for which the counterparty will pay at a designated later period at a price determined by the then current market price.

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs which generally do not extend the useful life of an asset for two or more years through the replacement of critical components are expensed as incurred. Major renewals and improvements that generally extend the useful lives of an asset for two or more years through the replacement of critical components are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset's estimated useful life. The Partnership follows the composite method of depreciation and has determined the composite groups to be the major asset classes of its gathering and processing systems. Under the composite depreciation method, any gain or loss upon disposition or retirement of pipeline, gas gathering and processing components, is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership's results of operations.

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 6).

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

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limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner s and the preferred unitholders interests. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2% general partner interest and incentive distributions to be distributed for the quarter (see Note 4), with a priority allocation of net income to the General Partner s incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner s and limited partners ownership interests.

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

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership s phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 13), 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.

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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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Continuing operations:				
Net income (loss)	\$ (6,356)	\$ 50,258	\$ 74,966	\$ 300,732
Income attributable to non-controlling interests	(1,511)	(1,760)	(4,108)	(4,492)
Preferred unit dividends				(389)
Net income (loss) attributable to common limited partners and the General Partner	(7,867)	48,498	70,858	295,851
General Partner's cash incentive distributions paid	1,572	441	4,537	441
General Partner's ownership interest	(190)	966	1,333	5,938
Net income attributable to the General Partner's ownership interests	1,382	1,407	5,870	6,379
Net income (loss) attributable to common limited partners	(9,249)	47,091	64,988	289,472
Net income attributable to participating securities – phantom units ⁽¹⁾		369	886	2,301
Net income (loss) utilized in the calculation of net income from continuing operations attributable to common limited partners per unit	\$ (9,249)	\$ 46,722	\$ 64,102	\$ 287,171
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). For the three months ended September 30, 2012 net loss attributable to common limited partners' ownership interest is not allocated to approximately 964,000 phantom units because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities and unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership's long-term incentive plans (see Note 13).

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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		Nine Months Ended	
	Ended September 30,		September 30,	
	2012	2011	2012	2011
Weighted average number of common limited partner units basic	53,736	53,588	53,668	53,494
Add effect of dilutive securities phantom unit ⁽¹⁾		424	741	429
Weighted average common limited partner units diluted	53,736	54,012	54,409	53,923

- (1) For the three months ended September 30, 2012 approximately 964,000 phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.

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

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arrangement. Also, because the natural gas volumes contracted under some Keep-Whole agreements are lower in BTU content and thus can meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods when the processing margin risk is uneconomic.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership's records and management estimates of the related gathering and compression fees which are, in turn, based upon applicable product prices. The Partnership had unbilled revenues at September 30, 2012 and December 31, 2011 of \$62.7 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 IFRS, 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 elected to adopt these requirements early and 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.

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On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain 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 on its consolidated statements of operations a \$255.7 million gain during the nine months ended September 30, 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 11) and for general company purposes.

The Partnership recognized its initial 49% non-controlling ownership interest in Laurel Mountain as an investment in joint ventures on its consolidated balance sheets at fair value based upon the value received for the 51% contributed to the Laurel Mountain joint venture during the year ended December 31, 2009. 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 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. 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 38 years. 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. The Partnership incurred costs of \$0.6 million during the nine months ended September 30, 2011, related to the acquisition of WTLPG, which are reported as other costs within the Partnership's consolidated statements of operations.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Equity income in Laurel Mountain	\$	\$	\$	\$ 462
Equity income in WTLPG	1,422	1,785	4,235	2,472
Equity income in joint ventures	\$ 1,422	\$ 1,785	\$ 4,235	\$ 2,934

NOTE 4 EQUITY*Common Units*

In August 2012, the Partnership filed a registration statement describing its intention to enter into an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, the Partnership may offer and sell from time to time through Citigroup, as its sales agent, common units having an aggregate value of up to \$150.0 million. Subject to the terms and conditions of the equity distribution agreement, Citigroup will not be required to sell any specific number or dollar amount of the common units, but will use its reasonable efforts, consistent with its normal trading and sales practices, to sell such units. Such sales will be at market prices prevailing at the time of the sale. There will be no specific date on which the offering will end; there will be no minimum purchase requirements; and there will be no arrangements to place the proceeds of the offering in an escrow, trust or similar account. Under the terms of the planned equity distribution agreement, the Partnership also may sell common units to Citigroup as principal for its own account at a price agreed upon at the time of the sale. The Partnership intends to use the net proceeds from any such offering for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. Amounts repaid under the Partnership's revolving credit facility may be reborrowed to fund ongoing capital programs, potential future acquisitions or for general partnership purposes. As of September 30, 2012, the equity distribution agreement had not been signed and no common units have been offered or sold under the registration statement. The Partnership will file a prospectus supplement upon the execution of the equity distribution agreement.

Preferred Units

On February 17, 2011, as part of the Chevron Merger (see Note 3), Chevron acquired 8,000 12% Cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units), which were previously owned by Atlas Energy, Inc. On May 27, 2011, the Partnership redeemed the Class C Preferred Units for cash at the liquidation value of \$1,000 per unit, or \$8.0 million, plus \$0.2 million of accrued dividends. The Partnership recognized \$0.4 million of preferred dividends for the nine months ended September 30, 2011 which are presented as reductions of net income to determine the net income attributable to common limited partners and the General Partner on its consolidated statements of operations.

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

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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 June 30, 2012 were as follows:

For Quarter Ended	Date Cash Distribution Paid	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
March 31, 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
March 31, 2012	May 15, 2012	0.56	30,030	2,217
June 30, 2012	August 14, 2012	0.56	30,085	2,221

On October 24, 2012, the Partnership declared a cash distribution of \$0.57 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2012. The \$33.1 million distribution, including \$2.4 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on November 14, 2012 to unitholders of record at the close of business on November 7, 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 11) (in thousands):

	September 30, 2012	December 31, 2011	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	\$ 1,886,927	\$ 1,615,015	2 40
Rights of way	176,116	161,191	20 40
Buildings	8,223	8,047	40
Furniture and equipment	10,140	9,392	3 7
Other	14,728	14,029	3 10
	2,096,134	1,807,674	
Less accumulated depreciation	(287,043)	(239,846)	
	\$ 1,809,091	\$ 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 5.7% and 6.3% for the three months ended September 30, 2012 and 2011, respectively, and 6.2% and 7.2% for the nine months ended September 30, 2012 and 2011, respectively. The amount of interest capitalized was \$2.2 million and \$1.7 million for the three months ended September 30, 2012 and 2011, respectively, and \$6.4 million and \$3.0 million for the nine months ended September 30, 2012 and 2011, respectively.

The Partnership recorded depreciation expense on property, plant and equipment, including amortization of capital lease arrangements (see Note 11), of \$16.9 million and \$13.8 million for the three months ended September 30, 2012 and 2011, respectively, and \$47.7 million and \$40.2 million for the nine months ended September 30, 2012 and 2011, respectively, on its consolidated statements of operations.

Table of Contents**NOTE 6 INTANGIBLE ASSETS**

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The Partnership completed acquisitions of various gas gathering systems and related assets during the nine months ended September 30, 2012. The Partnership accounted for these acquisitions as business combinations and recognized \$20.2 million related to customer contracts with an estimated useful life of 10-14 years. The initial recording of these transactions was based upon preliminary valuation assessments and is subject to change. The following table reflects the components of intangible assets being amortized at September 30, 2012 and December 31, 2011 (in thousands):

	September 30, 2012	December 31, 2011	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	\$ 20,230	\$	10 14
Customer relationships	205,313	205,313	7 10
	225,543	205,313	
Accumulated amortization:			
Customer contracts	(683)		
Customer relationships	(119,364)	(102,037)	
	(120,047)	(102,037)	
Net carrying amount:			
Customer contracts	19,547		
Customer relationships	85,949	103,276	
Net carrying amount	\$ 105,496	\$ 103,276	

The weighted-average amortization period for customer contracts and customer relationships is 12.1 years and 9.1 years, respectively. The Partnership recorded amortization expense on intangible assets of \$6.2 million and \$5.8 million for the three months ended September 30, 2012 and 2011, respectively, and \$18.0 million and \$17.3 million for the nine months ended September 30, 2012 and 2011, respectively, on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: remainder of 2012 \$6.2 million; 2013 \$24.8 million; 2014 \$21.3 million; 2015 to 2016 \$16.3 million per year.

NOTE 7 OTHER ASSETS

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

	September 30, 2012	December 31, 2011
Deferred finance costs, net of accumulated amortization of \$22,220 and \$18,864 at September 30, 2012 and December 31, 2011, respectively	\$ 26,784	\$ 20,750
Security deposits	2,223	4,399
	\$ 29,007	\$ 25,149

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 11). During the three months ended September 30, 2012 and 2011, the Partnership incurred \$6.0 million and \$1.1 million deferred finance costs, respectively, related to various financing

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activities. During the nine months ended September 30, 2012 and 2011, the Partnership incurred \$9.4 million and \$1.3 million deferred finance costs, respectively, related to various financing activities (see Note 11). During the nine months ended September 30, 2011, the Partnership recorded \$5.2 million related to accelerated amortization of deferred financing costs associated with the retirement of its 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes) and partial redemption of its 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes). This expense is included in loss on early extinguishment of debt on the Partnership's consolidated statements of operations (see Note 11). Amortization expense of deferred finance costs was \$1.1 million for each of the three months ended September 30, 2012 and 2011 and \$3.4 million for each of the nine months ended September 30, 2012 and 2011, which is recorded within interest expense on the Partnership's consolidated statements of operations.

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

The Partnership no longer applies hedge accounting for derivatives. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. The change in fair value of commodity-based derivative instruments, which was previously recognized in accumulated other comprehensive loss within equity on the Partnership's consolidated balance sheets, 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 \$1.1 million net loss in accumulated other comprehensive loss, within equity on the Partnership's consolidated balance sheets at September 30, 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 gain (loss), net as unrealized gain (loss) on the Partnership's consolidated statements of operations. Premiums are reclassified to realized gain (loss) within derivative gain (loss), net at the time the option expires or is exercised. The Partnership reflected net derivative assets on its consolidated balance sheets of \$43.4 million and \$16.5 million at September 30, 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 derivative assets and liabilities on the Partnership's consolidated balance sheets for the periods indicated (in thousands):

	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 September 30, 2012</u>			
Current portion of derivative assets	\$ 27,830	\$ (1,610)	\$ 26,220
Long-term portion of derivative assets	19,030	(1,835)	17,195
Total derivative assets, net	\$ 46,860	\$ (3,445)	\$ 43,415
<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

	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 September 30, 2012</u>			
Current portion of derivative liabilities	\$ (1,610)	\$ 1,610	\$
Long-term portion of derivative liabilities	(1,835)	1,835	
Total derivative liabilities, net	\$ (3,445)	\$ 3,445	\$
<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	\$

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The following table summarizes the Partnership's commodity derivatives as of September 30, 2012, (dollars and volumes in thousands):

Production Period	Commodity	Volumes ⁽¹⁾	Average Fixed Price (\$/Volume)	Fair Value ⁽²⁾ Asset/ (Liability)
Fixed price swaps				
2012	Natural gas	1,140	\$ 3.28	\$ (51)
2013	Natural gas	1,200	3.48	(388)
2014	Natural gas	5,400	3.90	(1,498)
2012	NGLs	8,316	1.58	2,971
2013	NGLs	52,416	1.27	15,554
2014	NGLs	21,420	1.25	2,059
2012	Crude oil	75	95.58	225
2013	Crude oil	345	97.17	1,181
2014	Crude oil	180	92.27	130
Total fixed price swaps				\$ 20,183
Options				
Purchased put options				
2012	NGLs	15,498	\$ 1.57	\$ 4,159
2013	NGLs	38,556	1.94	10,635
2012	Crude oil	39	105.80	540
2013	Crude oil	282	100.10	3,624
2014	Crude oil	332	95.74	4,719
Purchased call options⁽³⁾				
2012	Crude oil	45	125.20	4
Sold call options⁽³⁾				
2012	Crude oil	125	94.69	(449)
Total options				23,232
Total derivatives				\$ 43,415

(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 September 30,		For the Nine Months ended September 30,	
	2012	2011	2012	2011
Derivatives previously designated as cash flow hedges	\$ (1,079)	\$ (1,714)	\$ (3,333)	\$ (5,118)

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Loss reclassified from accumulated other comprehensive loss into natural gas and liquids sales

Derivatives not designated as hedges					
Commodity contract	realized ⁽¹⁾	\$ 4,157	\$ (2,603)	\$ 7,079	\$ (11,396)
Commodity contract	unrealized ⁽²⁾	(23,064)	26,363	29,826	20,348
Derivative gain (loss), net		\$ (18,907)	\$ 23,760	\$ 36,905	\$ 8,952

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

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NOTE 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, whereas unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

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

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

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

The Partnership uses a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 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 and NGL Linefill

At September 30, 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.

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

The following table represents the Partnership's derivative assets and liabilities recorded at fair value as of September 30, 2012 and December 31, 2011 (in thousands):

	Level 1	Level 2	Level 3	Total
As of September 30, 2012				
Derivative assets, gross				
Commodity swaps	\$	\$ 2,521	\$ 20,658	\$ 23,179
Commodity options		8,887	14,794	23,681
Total derivative assets, gross		11,408	35,452	46,860
Derivative liabilities, gross				
Commodity swaps		(2,922)	(74)	(2,996)
Commodity options		(449)		(449)
Total derivative liabilities, gross		(3,371)	(74)	(3,445)
Total derivatives, fair value, net	\$	\$ 8,037	\$ 35,378	\$ 43,415
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

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The following table provides a summary of changes in fair value of the Partnership's Level 3 derivative instruments for the nine months ended September 30, 2012 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total Amount
	Gallons	Amount	Gallons	Amount	
Balance December 31, 2011	49,644	\$ (1,733)	92,610	\$ 18,279	\$ 16,546
New contracts ⁽¹⁾	71,064				
Cash settlements from unrealized gain (loss) ⁽²⁾⁽³⁾	(38,556)	(5,324)	(38,556)	(190)	(5,514)
Net change in unrealized gain (loss) ⁽²⁾		27,641		5,553	33,194
Deferred option premium recognition ⁽³⁾				(8,848)	(8,848)
Balance September 30, 2012	82,152	\$ 20,584	54,054	\$ 14,794	\$ 35,378

(1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.

(2) Included within derivative gain (loss), net on the Partnership's consolidated statements of operations.

(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

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 September 30, 2012 and December 31, 2011 (in thousands):

	Gallons	Third Party Quotes ⁽¹⁾	Adjustments ⁽²⁾	Total Amount
As of September 30, 2012				
Propane swaps	69,678	\$ 18,828	\$ (612)	\$ 18,216
Isobutane swaps	1,890	(223)	313	90
Normal butane swaps	3,780	415	189	604
Natural gasoline swaps	6,804	2,827	(1,153)	1,674
Total NGL swaps September 30, 2012	82,152	\$ 21,847	\$ (1,263)	\$ 20,584
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)

(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.

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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 NGL Swap Fair Value Adjustments	Adjustment based upon Regression Coefficient		
		Lower 95%	Upper 95%	Average
As of September 30, 2012				
Propane Conway	\$ (612)	0.9086	0.9194	0.9140
Isobutane	313	1.1253	1.1344	1.1299
Normal butane	189	1.0365	1.0412	1.0388
Natural gasoline	(1,153)	0.8990	0.9138	0.9064
Total Level 3 adjustments September 30, 2012	\$ (1,263)			
As of December 31, 2011				
Isobutane	\$ 570	1.1239	1.1333	1.1286
Normal butane	343	1.0311	1.0355	1.0333
Natural gasoline	(515)	0.9351	0.9426	0.9389
Total Level 3 adjustments December 31, 2011	\$ 398			

The Partnership had \$6.7 million and \$11.5 million of NGL linefill at September 30, 2012 and December 31, 2011, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties for which the counterparty will pay at a designated later period at a price determined by the then market price. The Partnership's NGL linefill is defined as a Level 3 asset and is valued using the same forward price curve utilized to value the Partnership's NGL fixed price swaps. The product/location adjustment based upon the multiple regression analysis, which was included in the value of the linefill, was a reduction of \$0.5 million and \$0.8 million as of September 30, 2012 and December 31, 2011, respectively.

The following table provides a summary of changes in fair value of the Partnership's NGL linefill for the nine months ended September 30, 2012 (in thousands):

	NGL Linefill	
	Gallons	Amount
Balance December 31, 2011	10,408	\$ 11,529
Cash settlements ⁽¹⁾	(2,520)	(2,698)
Net change in NGL linefill valuation ⁽¹⁾		(2,120)
Balance September 30, 2012	7,888	\$ 6,711

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

In February 2012, the Partnership acquired a gas gathering system and related assets for an initial net purchase price of \$19.0 million. The Partnership agreed to pay up to an additional \$12.0 million, payable in two equal amounts (Trigger Payments), if certain volumes are achieved on the acquired gathering system within a specified time period. The fair value of the Trigger Payments recognized upon acquisition resulted in a \$6.0 million current liability, which was recorded within accrued liabilities on the Partnership's consolidated balance sheets, and a \$6.0 million

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long term liability, which was recorded within other long term liabilities on the Partnership's consolidated balance sheets. The initial recording of the transaction was based upon preliminary valuation assessments and is subject to change. The range of the undiscounted amounts the Partnership could pay related to the Trigger Payments is between \$0 and \$12.0 million.

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The estimated fair value of the Partnership's other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership's current assets and liabilities on its consolidated balance sheets, other than the derivatives, NGL linefill and contingent consideration discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1 values. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value and thus is categorized as a Level 1 value. The estimated fair value of the Partnership's Senior Notes is based upon the market approach and calculated using the yield of the Senior Notes as provided by financial institutions and thus is categorized as a Level 3 value. The estimated fair values of the Partnership's total debt at September 30, 2012 and December 31, 2011, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were \$820.3 million and \$537.3 million, respectively, compared with the carrying amounts of \$786.6 million and \$524.1 million, respectively.

NOTE 10 ACCRUED LIABILITIES

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

	September 30, 2012	December 31, 2011
Accrued capital expenditures	\$ 9,991	\$ 10,128
Accrued ad valorem taxes	9,763	3,615
Acquisition-based short-term contingent consideration	6,000	
Other	5,494	9,539
	\$ 31,248	\$ 23,282

NOTE 11 DEBT

Total debt consists of the following (in thousands):

	September 30, 2012	December 31, 2011
Revolving credit facility	\$ 80,000	\$ 142,000
8.750% Senior notes due 2018	370,384	370,983
6.625% Senior notes due 2020	325,000	
Capital lease obligations	11,229	11,157
Total debt	786,613	524,140
Less current maturities	(11,103)	(2,085)
Total long-term debt	\$ 775,510	\$ 522,055

Cash payments for interest related to debt, net of capitalized interest, were \$0.9 million and \$3 thousand for the three months ended September 30, 2012 and 2011, respectively, and \$16.2 million and \$17.2 million for the nine months ended September 30, 2012 and 2011, respectively.

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Revolving Credit Facility

At September 30, 2012, the Partnership had a \$600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. Borrowings under the revolving credit facility bear interest, at the Partnership's option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% and (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at September 30, 2012, was 2.5%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$0.1 million was outstanding at September 30, 2012. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At September 30, 2012, the Partnership had \$519.9 million of remaining committed capacity under its revolving credit facility.

On May 31, 2012, the Partnership entered into an amendment to its revolving credit facility agreement, which among other changes:

increased the revolving credit facility from \$450.0 million to \$600.0 million;

extended the maturity date from December 22, 2015 to May 31, 2017;

reduced the Applicable Margin used to determine interest rates by 0.50%;

revised the negative covenants to (i) permit investments in joint ventures equal to the greater of 20% of Consolidated Net Tangible Assets (as defined in the credit agreement) or \$340 million, provided the Partnership meets certain requirements, and (ii) increased the general investment basket to 5% of Consolidated Net Tangible Assets ;

revised the definition of Consolidated EBITDA to provide for the inclusion of the first twelve months of projected revenues for identified capital expansion projects, upon completion of the projects and contingent upon prior approval by the administrative agent. The addition from any such projects, in the aggregate, may not exceed 15% of unadjusted Consolidated EBITDA; and

provided for the potential increase of revolving credit commitments up to an additional \$200.0 million.

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 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.

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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 September 30, 2012, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At September 30, 2012, the Partnership had \$370.4 million principal amount outstanding of 8.75% Senior Notes and \$325.0 million principal amount outstanding of 6.625% senior unsecured notes due on October 1, 2020 (6.625% Senior Notes), and with the 8.75% Senior Notes, the Senior Notes).

The 8.75% Senior Notes are presented combined with a net \$4.6 million unamortized premium as of September 30, 2012. 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.

On April 7, 2011, the Partnership redeemed \$7.2 million of the 8.75% Senior Notes, which were tendered upon its offer to purchase the 8.75% Senior Notes, at par. The sale of the Partnership's 49% non-controlling interest in Laurel Mountain on February 17, 2011 (see Note 3) constituted an Asset Sale pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, the Partnership offered to purchase the 8.75% Senior Notes.

On September 28, 2012, the Partnership issued \$325.0 million of the 6.625% Senior Notes in a private placement transaction. The 6.625% Senior Notes were issued at par. The Partnership received net proceeds of \$319.1 million after underwriting commissions and other transaction costs and utilized the proceeds to reduce the outstanding balance on its revolving credit facility. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest at the date of redemption.

In connection with the issuance of the 6.625% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by September 23, 2013. If the Partnership does not meet the aforementioned deadline, the 6.625% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the Partnership causes the exchange offer to be consummated.

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

Indentures governing the Senior Notes contain covenants, including limitations of the Partnership's ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all its assets. The Partnership is in compliance with these covenants as of September 30, 2012.

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On April 8, 2011, the Partnership redeemed all of the 8.125% Senior Notes. 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 paid \$293.7 million to redeem the \$275.5 million principal plus \$11.2 million premium and \$7.0 million accrued interest.

Capital Leases

On July 15, 2011, the Partnership amended an operating lease for eight natural gas compressors to require a mandatory purchase of the equipment at the end of the lease term, thereby converting the agreement to a capital lease upon the effective date of the amendment. As a result, the Partnership recorded an asset of \$11.4 million 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 on the minimum payments required under the lease and the Partnership's incremental borrowing rate. During the nine months ended September 30, 2012, the Partnership recorded \$1.9 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 September 30, 2012 and December 31, 2011, which are included within property, plant and equipment (see Note 5) (in thousands):

	September 30, 2012	December 31, 2011
Pipelines, processing and compression facilities	\$ 14,512	\$ 12,507
Less accumulated depreciation	(881)	(199)
	\$ 13,631	\$ 12,308

Depreciation expense for leased properties was \$186 thousand and \$109 thousand for the three months ended September 30, 2012 and 2011, respectively and \$538 thousand and \$137 thousand for the nine months ended September 30, 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 September 30, 2012, future minimum lease payments related to the capital leases are as follows (in thousands):

	Capital Lease Minimum Payments
2012	\$ 833
2013	10,879
2014	64
2015	
2016	
Thereafter	
Total minimum lease payments	11,776
Less amounts representing interest	(547)
Present value of minimum lease payments	11,229
Less current portion of capital lease obligations	(11,103)
Long-term capital lease obligations	\$ 126

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NOTE 12 COMMITMENTS AND CONTINGENCIES

The Partnership has certain long-term unconditional purchase obligations and commitments, consisting primarily of transportation contracts. These agreements provide for transportation services to be used in the ordinary course of the Partnership's operations. Transportation fees paid related to these contracts were \$2.6 million and \$2.6 million for three months ended September 30, 2012 and 2011, respectively and \$7.6 million and \$7.5 million for nine months ended September 30, 2012 and 2011, respectively. The future fixed and determinable portion of the obligations as of September 30, 2012 was as follows: remainder of 2012 \$2.1 million; 2013 \$9.0 million; 2014 \$9.2 million; 2015 and 2016 \$3.0 million per year.

The Partnership had committed approximately \$133.0 million for the purchase of property, plant and equipment at September 30, 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 13 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 General Partner and within the guidelines prescribed 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 September 30, 2012, the Partnership had

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960,918 phantom units outstanding under the LTIPs, with 1,636,042 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options, which have vested and have been exercised.

Partnership Phantom Units. Through September 30, 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 September 30, 2012, there were 264,597 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 September 30, 2012 include DERs granted to the participants by the LTIP Committee. The amounts paid with respect to LTIP DERs were \$0.6 million and \$0.2 million, during the three months ended September 30, 2012 and 2011, respectively and \$1.4 million and \$0.6 million, during the nine months ended September 30, 2012 and 2011, respectively. These amounts were recorded as reductions of equity on the Partnership s consolidated balance sheets.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
	Number of Units	Fair Value ⁽¹⁾	Number of Units	Fair Value ⁽¹⁾	Number of Units	Fair Value ⁽¹⁾	Number of Units	Fair Value ⁽¹⁾
Outstanding, beginning of period	972,402	\$ 32.19	436,425	\$ 17.84	394,489	\$ 21.63	490,886	\$ 11.75
Granted	85,103	33.61	7,465	27.30	783,187	34.83	138,318	32.99
Forfeited	(51,000)	29.83	(7,750)	26.99	(54,950)	29.46	(7,750)	26.99
Matured and issued ⁽²⁾	(45,587)	23.75	(46,375)	11.02	(161,808)	16.26	(231,689)	11.31
Outstanding, end of period ⁽³⁾⁽⁴⁾	960,918	\$ 32.84	389,765	\$ 19.24	960,918	\$ 32.84	389,765	\$ 19.24
Matured and not issued ⁽⁵⁾	6,800	\$ 27.46	750	\$ 11.12	6,800	\$ 27.46	750	\$ 11.12
Non-cash compensation expense recognized (in thousands) ⁽⁶⁾		\$ 3,619		\$ 822		\$ 7,538		\$ 2,498

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

(2) The intrinsic values for phantom unit awards exercised during the three months ended September 30, 2012 and 2011 were \$1.4 million and \$1.5 million, respectively, and \$4.9 million and \$7.4 million during the nine months ended September 30, 2012 and 2011, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at September 30, 2012 and 2011 was \$32.8 million and \$11.6 million, respectively.

(4) There were 18,952 and 15,701 outstanding phantom unit awards at September 30, 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 September 30, 2012 and 2011 was \$157 thousand and \$24 thousand, respectively.

(6) Non-cash compensation expense for the nine months ended September 30, 2011 includes incremental compensation expense of \$0.5 million, related to the accelerated vesting of phantom units held by the CEO of the General Partner.

At September 30, 2012, the Partnership had approximately \$23.4 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.2 years.

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Partnership Unit Options. At September 30, 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 September 30, 2012, all unit options had been exercised.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	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) ⁽²⁾		\$		\$		\$		\$ 3

(1) The intrinsic value for option unit awards exercised during the nine months ended September 30, 2011 was \$1.8 million. Approximately \$0.5 million was received from exercise of unit option awards during the nine months ended September 30, 2011.

(2) Non-cash compensation expense for the nine months ended September 30, 2011 includes incremental compensation expense of \$2 thousand, related to the accelerated vesting of options held by the CEO of the General Partner.

Employee Incentive Compensation Plan and Agreement

At September 30, 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 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. During the nine months ended September 30, 2012 and 2011, 25,500 Bonus Units and 24,750 Bonus Units, respectively, vested and cash payments were made for \$0.7 million and \$0.9 million, respectively. 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 income of \$79 thousand during the nine months ended September 31, 2012 and expense of \$630 thousand during the nine months ended September 31, 2011, which was recorded within general and administrative expense on its consolidated statements of operations. The Partnership had \$0.8 million at December 31, 2011 included within accrued liabilities on its consolidated balance sheets with regard to these awards, which represents their fair value as of that date. At September 30, 2012, the Partnership had no outstanding Bonus Units.

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NOTE 14 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 \$0.8 million and \$0.4 million for the three months ended September 30, 2012 and 2011, respectively, and \$2.6 million \$1.3 million for the nine months ended September 30, 2011 and 2010, 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 nine months ended September 30, 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).

In June 2012, the Partnership acquired a gas gathering system and related assets in the Barnett Shale play in Tarrant County, Texas. The system consists of 19 miles of gathering pipeline that is used to facilitate gathering some of the newly-acquired production for Atlas Resources Partners, L.P. (NYSE: ARP) (ARP). ARP's general partner is wholly-owned by Atlas Energy, and two members of the General Partner's managing board are members of ARP's board of directors. By virtue of the acquisition, the Partnership became party to a management and operating services agreement (which had been negotiated and was in existence between unaffiliated third parties prior to the acquisition), whereby ARP now operates the gathering system on the Partnership's behalf and the Partnership will pay them annual management and operating fees of approximately \$325 thousand to cover ARP's cost of services.

NOTE 15 SEGMENT INFORMATION

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

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; (2) the natural gas gathering assets located in Tennessee; and (3) the revenues and gain on sale related to the Partnership's former 49% non-controlling interest in Laurel Mountain. 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 Partnership's 20% interest in the equity income generated by WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Pipeline revenues are primarily derived from transportation fees.

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

	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
Three months ended September 30, 2012:				
Revenue:				
Revenues - third party ^(b)	\$ 297,478	\$	\$ (20,066)	\$ 277,412
Revenues - affiliates	156			156
Total revenues	297,634		(20,066)	277,568
Costs and expenses:				
Operating costs and expenses	240,321	49		240,370
General and administrative ⁽¹⁾			12,123	12,123
Depreciation and amortization	23,161			23,161
Interest expense ⁽¹⁾			9,692	9,692
Total costs and expenses	263,482	49	21,815	285,346
Equity income in joint ventures		1,422		1,422
Net income (loss)	\$ 34,152	\$ 1,373	\$ (41,881)	\$ (6,356)
Three months ended September 30, 2011:				
Revenue:				
Revenues - third party ^(b)	\$ 357,655	\$	\$ 22,046	\$ 379,701
Revenues - affiliates	79			79
Total revenues	357,734		22,046	379,780
Costs and expenses:				
Operating costs and expenses	296,615	137		296,752
General and administrative ⁽¹⁾			9,149	9,149
Depreciation and amortization	19,471			19,471
Interest expense ⁽¹⁾			5,935	5,935
Total costs and expenses	316,086	137	15,084	331,307
Equity income in joint ventures		1,785		1,785
Net income (loss)	\$ 41,648	\$ 1,648	\$ 6,962	\$ 50,258

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	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
Nine months ended September 30, 2012:				
Revenue:				
Revenues third party ⁽¹⁾	\$ 860,119	\$	\$ 33,492	\$ 893,611
Revenues affiliates	357			357
Total revenues	860,476		33,492	893,968
Costs and expenses:				
Operating costs and expenses	697,218	122		697,340
General and administrative ⁽¹⁾			32,513	32,513
Depreciation and amortization	65,715			65,715
Interest expense ⁽¹⁾			27,669	27,669
Total costs and expenses	762,933	122	60,182	823,237
Equity income in joint ventures		4,235		4,235
Net income (loss)	\$ 97,543	\$ 4,113	\$ (26,690)	\$ 74,966
Nine Months Ended September 30, 2011:				
Revenue:				
Revenues third party ⁽¹⁾	\$ 982,739	\$	\$ 3,833	\$ 986,572
Revenues affiliates	256			256
Total revenues	982,995		3,833	986,828
Costs and expenses:				
Operating costs and expenses	815,573	712		816,285
General and administrative ⁽¹⁾			26,821	26,821
Depreciation and amortization	57,499			57,499
Interest expense ⁽¹⁾			24,525	24,525
Total costs and expenses	873,072	712	51,346	925,130
Equity income	462	2,472		2,934
Gain on sale of assets	255,674			255,674
Loss on early extinguishment of debt			(19,574)	(19,574)
Net income (loss) from continuing operations	366,059	1,760	(67,087)	300,732
Loss from discontinued operations			(81)	(81)
Net income (loss)	\$ 366,059	\$ 1,760	\$ (67,168)	\$ 300,651

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

Three Months Ended
September 30,

Nine Months Ended
September 30,

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	2012	2011	2012	2011
Capital Expenditures:				
Gathering and Processing	\$ 96,024	\$ 56,175	\$ 242,412	\$ 148,144
Pipeline				
	\$ 96,024	\$ 56,175	\$ 242,412	\$ 148,144

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	September 30, 2012	December 31, 2011
Balance Sheet		
Investment in joint ventures:		
Pipeline	\$ 85,714	\$ 86,879
	\$ 85,714	\$ 86,879
Total assets:		
Gathering and processing	\$ 2,026,947	\$ 1,806,550
Pipeline	85,796	87,053
Corporate and other	79,098	37,209
	\$ 2,191,841	\$ 1,930,812

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Natural gas and liquids sales:				
Natural gas	\$ 111,402	\$ 112,909	\$ 260,046	\$ 299,566
NGLs	140,065	209,941	477,918	582,806
Condensate	22,776	19,070	66,800	56,268
Other	375	(422)	(2,120)	(665)
Total	\$ 274,618	\$ 341,498	\$ 802,644	\$ 937,975

Table of Contents**NOTE 16 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION**

The Partnership's Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership's consolidated financial statements as of September 30, 2012 and December 31, 2011 and for the three and nine months ended September 30, 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 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 September 30, 2012 and December 31, 2011 and for the three and nine months ended September 30, 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):

Balance Sheets

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
September 30, 2012					
Assets					
Cash and cash equivalents	\$	\$ 165	\$	\$	\$ 165
Accounts receivable - affiliates	541,838	40,365		(582,203)	
Other current assets	280	45,366	100,675	(1,148)	145,173
Total current assets	542,118	85,896	100,675	(583,351)	145,338
Property, plant and equipment, net		298,861	1,510,230		1,809,091
Intangible assets, net		9,358	96,138		105,496
Investment in joint ventures		85,714			85,714
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,440,418	1,905,294		(3,345,712)	
Other assets, net	26,784	18,968	450		46,202
Total assets	\$ 2,009,320	\$ 2,404,091	\$ 3,560,421	\$ (5,781,991)	\$ 2,191,841

Liabilities and Equity					
Accounts payable - affiliates	\$	\$	\$ 584,742	\$ (582,203)	\$ 2,539
Other current liabilities	9,744	17,483	156,047		183,274
Total current liabilities	9,744	17,483	740,789	(582,203)	185,813
Long-term debt, less current portion	775,384		126		775,510
Other long-term liability	132	326	6,000		6,458
Equity	1,224,060	2,386,282	2,813,506	(5,199,788)	1,224,060
Total liabilities and equity	\$ 2,009,320	\$ 2,404,091	\$ 3,560,421	\$ (5,781,991)	\$ 2,191,841

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

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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 notes receivable			1,852,928	(1,852,928)	
Equity investments	1,427,152	2,035,533		(3,462,685)	
Other assets, net	20,750	16,587	2,626		39,963
Total assets	\$ 1,750,890	\$ 2,488,315	\$ 3,354,558	\$ (5,662,951)	\$ 1,930,812

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 and Other Comprehensive Income**

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended September 30, 2012					
Total revenues	\$	\$ 26,342	\$ 251,226	\$	\$ 277,568
Total costs and expenses	(8,476)	(59,075)	(217,795)		(285,346)
Equity income	609	36,688		(35,875)	1,422
Net income (loss)	(7,867)	3,955	33,431	(35,875)	(6,356)
Income attributable to non-controlling interest			(1,511)		(1,511)
Net income (loss) attributable to common limited partners and the General Partner	(7,867)	3,955	31,920	(35,875)	(7,867)
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	1,079	1,079		(1,079)	1,079
Comprehensive income (loss)	\$ (6,788)	\$ 5,034	\$ 31,920	\$ (36,954)	\$ (6,788)
Three Months Ended September 30, 2011					
Total revenues	\$	\$ 95,458	\$ 284,322	\$	\$ 379,780
Total costs and expenses	(3,857)	(81,241)	(246,209)		(331,307)
Equity income	53,613	40,460		(92,288)	1,785
Net income (loss)	49,756	\$ 54,677	\$ 38,113	\$ (92,288)	\$ 50,258
Income attributable to non-controlling interest			(1,760)		(1,760)
Net income (loss) attributable to common limited partners and the General Partner	49,756	54,677	36,353	(92,288)	48,498
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	1,714	1,714		(1,714)	1,714
Comprehensive income (loss)	\$ 51,470	\$ 56,391	\$ 36,353	\$ (94,002)	\$ 50,212

Table of Contents**Statements of Operations and Other Comprehensive Income**

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
<u>Nine Months Ended September 30, 2012</u>					
Total revenues	\$	\$ 192,181	\$ 701,787	\$	\$ 893,968
Total costs and expenses	(25,305)	(189,612)	(608,320)		(823,237)
Equity income	96,163	97,735		(189,663)	4,235
Net income (loss)	70,858	100,304	93,467	(189,663)	74,966
Income attributable to non-controlling interest			(4,108)		(4,108)
Net income (loss) attributable to common limited partners and the General Partner	70,858	100,304	89,359	(189,663)	70,858
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	3,333	3,333		(3,333)	3,333
Comprehensive income (loss)	\$ 74,191	\$ 103,637	\$ 89,359	\$ (192,996)	\$ 74,191
<u>Nine Months Ended September 30, 2011</u>					
Total revenues	\$	\$ 202,637	\$ 784,191	\$	\$ 986,828
Total costs and expenses	(19,661)	(221,578)	(683,891)		(925,130)
Equity income	337,728	103,357		(438,151)	2,934
Gain on asset sale		255,674			255,674
Loss on early extinguishment of debt	(19,574)				(19,574)
Income (loss) from continuing operations	298,493	340,090	100,300	(438,151)	300,732
Loss from discontinued operations		(81)			(81)
Net income (loss)	298,493	340,009	100,300	(438,151)	300,651
Income attributable to non-controlling interest			(4,492)		(4,492)
Preferred unit dividends	(389)				(389)
Net income (loss) attributable to common limited partners and the General Partner	298,104	340,009	95,808	(438,151)	295,770
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income (loss)	5,118	5,118		(5,118)	5,118
Comprehensive income (loss)	\$ 303,222	\$ 345,127	\$ 95,808	\$ (443,269)	\$ 300,888

Table of Contents**Statements of Cash Flows**

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
<u>Nine Months Ended September 30, 2012</u>					
Net cash provided by (used in):					
Operating activities	\$ (141,785)	\$ 85,766	\$ 139,984	\$ 41,558	\$ 125,523
Investing activities	(13,266)	84,747	(233,233)	(116,973)	(278,725)
Financing activities	155,051	(170,516)	93,249	75,415	153,199
Net change in cash and cash equivalents		(3)			(3)
Cash and cash equivalents, beginning of period		168			168
Cash and cash equivalents, end of period	\$	\$ 165	\$	\$	\$ 165

<u>Nine Months Ended September 30, 2011</u>					
Net cash provided by (used in):					
Operating activities	\$ (21,998)	\$ 34,831	\$ 164,961	\$ (97,136)	\$ 80,658
Continuing investing activities	268,195	292,617	(123,226)	(271,511)	166,075
Discontinued investing activities		(81)			(81)
Investing activities	268,195	292,536	(123,226)	(271,511)	165,994
Financing activities	(246,197)	(327,364)	(41,735)	368,647	(246,649)
Net change in cash and cash equivalents		3			3
Cash and cash equivalents, beginning of period		164			164
Cash and cash equivalents, end of period	\$	\$ 167	\$	\$	\$ 167

NOTE 17 SUBSEQUENT EVENTS

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 other than the distribution declared on October 24, 2012 (see Note 4).

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements

When used in this Form 10-Q, the words *believes*, *anticipates*, *expects* and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 1A, under the caption

Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 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.

We conduct our business in the midstream segment of the natural gas industry through two 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; (2) the natural gas gathering assets located in Tennessee; and (3) the revenues and gain on sale related to our former 49% interest in Laurel Mountain. 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 nine natural gas processing plants with aggregate capacity of approximately 870 MMCFD, which are connected to approximately 9,600 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.

Our Pipeline Transportation operations consist of a 20% interest in West Texas LPG Pipeline Limited Partnership (*WTLPG*), which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. *WTLPG* is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (*Chevron* NYSE: *CVX*), which owns the remaining 80% interest.

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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.

On May 31, 2012, we entered into an amendment to the revolving credit facility agreement, which among other changes: (1) increased the revolving credit facility from \$450.0 million to \$600.0 million; (2) extended the maturity date from December 22, 2015 to May 31, 2017; (3) reduced the Applicable Margin used to determine interest rates by 0.50%; (4) revised the negative covenants to (i) permit investments in joint ventures equal to the greater of 20% of Consolidated Net Tangible Assets (as defined in the Credit Agreement) or \$340 million, provided we meet certain requirements, and (ii) increased the general investment basket to 5% of Consolidated Net Tangible Assets; (5) revised the definition of Consolidated EBITDA to provide for the inclusion of the first twelve months of projected revenues for identified capital expansion projects, upon completion of the projects; and (6) provided for the option of additional revolving credit commitments of up to \$200.0 million.

In June 2012, we completed construction of, and started processing through, a 60 MMCFD cryogenic facility at the Velma gas plant, increasing capacity at Velma to 160 MMCFD. This expansion supports our long-term fee-based agreement with XTO Energy, Inc., a subsidiary of ExxonMobil, to provide natural gas gathering and processing services for up to an incremental 60 MMCFD from the Woodford Shale.

In June 2012, we acquired a gas gathering system and related assets in the Barnett Shale play in Tarrant County, Texas for an initial net purchase price of \$18.0 million. We accounted for the acquisition as a business combination. The system consists of 19 miles of gathering pipeline that is used to facilitate gathering some of the newly acquired production for our affiliate, Atlas Resources Partners, L.P. (ARP). ARP 's general partner is wholly-owned by ATLS, and two members of our General Partner 's managing board are members of ARP 's board of directors. By virtue of the acquisition we became party to a management and operating services agreement (which had been negotiated and was in existence between unaffiliated third parties prior to the acquisition), whereby ARP now operates the gathering system on our behalf and we will pay them annual management and operating fees of approximately \$325 thousand to cover ARP 's cost of services.

In August 2012, we filed a registration statement describing our intention to enter into an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, we may offer and sell from time to time through Citigroup, common units having an aggregate value of up to \$150.0 million. Citigroup will not be required to sell any specific number or dollar amount of the common units, but will use its reasonable efforts, consistent with its normal trading and sales practices, to sell such units. Such sales will be at market prices prevailing at the time of the sale. We intend to use the net proceeds from any such offering for general partnership purposes. As of September 30, 2012, the equity distribution agreement had not been signed and no common units have been offered or sold under the registration statement. We will file a prospectus supplement upon the execution of the equity distribution agreement.

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In September 2012, we issued \$325.0 million of 6.625% senior unsecured notes due on October 1, 2020 (6.625% Senior Notes) in a private placement transaction. We received net proceeds of \$319.1 million and utilized the proceeds to reduce the outstanding balance on our revolving credit facility (see Senior Notes).

In September 2012, we completed construction of, and started processing through, a 200 MMCFD cryogenic processing plant, referred to as the Waynoka II plant, on our WestOK gathering and processing system. This expansion brings the total nameplate processing capacity in the WestOK system to 458 MMCFD.

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).

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

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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, 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 and excludes the capital expansion add back included in Consolidated EBITDA as defined in the credit facility (see [Revolving Credit Facility](#)).

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

Distributable Cash Flow. We define distributable cash flow as net income plus 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).

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

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

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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 and nine months ended September 30, 2012 and 2011 (in thousands):

RECONCILIATION OF GROSS MARGIN

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011 ⁽¹⁾	2012	2011 ⁽¹⁾
Net income (loss)	\$ (6,356)	\$ 50,258	\$ 74,966	\$ 300,651
Derivative (gain) loss, net ⁽¹⁾	18,907	(23,760)	(36,905)	(8,952)
Other income, net ⁽¹⁾	(2,585)	(2,831)	(7,588)	(8,365)
Operating expenses ⁽²⁾	15,700	14,353	44,657	40,843
General and administrative expense ⁽³⁾	12,123	9,149	32,513	26,821
Other costs	(108)	8	(303)	583
Depreciation and amortization	23,161	19,471	65,715	57,499
Interest	9,692	5,935	27,669	24,525
Equity income in joint ventures	(1,422)	(1,785)	(4,235)	(2,934)
Gain on asset sale ⁽⁴⁾				(255,593)
Loss on early extinguishment of debt				19,574
Non-cash linefill (gain) loss ⁽⁵⁾	(375)	422	2,120	665
Gross margin	\$ 68,737	\$ 71,220	\$ 198,609	\$ 195,317

- (1) Adjusted to separately present derivative gain (loss), net instead of combining these amounts in other income, net.
- (2) Operating expenses include plant operating expenses; and transportation and compression expenses.
- (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 the sale of Elk City system.
- (5) Represents the non-cash impact of commodity price movements on pipeline linefill.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income	\$ (6,356)	\$ 50,258	\$ 74,966	\$ 300,651
Income attributable to non-controlling interests ⁽¹⁾	(1,511)	(1,760)	(4,108)	(4,492)
Interest expense	9,692	5,935	27,669	24,525
Depreciation and amortization	23,161	19,471	65,715	57,499
EBITDA	24,986	73,904	164,242	378,183
Equity income in joint ventures	(1,422)	(1,785)	(4,235)	(2,934)
Distributions from joint ventures	1,800	784	5,400	2,548
Gain on asset sale ⁽²⁾				(255,593)
Loss on early extinguishment of debt				19,574
Non-cash (gain) loss on derivatives ⁽³⁾	22,477	(27,049)	(31,568)	(22,477)
Premium expense on derivative instruments	4,855	2,599	12,591	9,314
Non-cash compensation	3,620	828	7,538	2,507
Non-cash line fill (gain) loss ⁽⁴⁾	(375)	422	2,120	665
Adjusted EBITDA	55,941	49,703	156,088	131,787
Interest expense	(9,692)	(5,935)	(27,669)	(24,525)
Amortization of deferred finance costs	1,061	1,053	3,356	3,354
Preferred dividend obligation				(389)
Proceeds remaining from asset sale ⁽⁵⁾				5,850
Premium expense on derivative instruments	(4,855)	(2,599)	(12,591)	(9,314)
Other costs	(108)	8	(303)	583
Maintenance capital	(4,732)	(4,980)	(13,242)	(13,451)
Distributable Cash Flow	\$ 37,615	\$ 37,250	\$ 105,639	\$ 93,895

- (1) Represents Anadarko's non-controlling interest in the operating results of the WestOK and WestTX systems.
- (2) Represents the gain on sale of Laurel Mountain and an adjustment to the gain on sale of our Elk City system.
- (3) Represents non-cash derivative (gains) losses as a result of the mark-to-market revaluation recognized on open derivative contracts, which have not yet been settled and the non-cash recognition of previously settled contracts reclassified from accumulated other comprehensive loss into natural gas and liquids sales
- (4) Represents the non-cash impact of commodity price movements on pipeline linefill.
- (5) Net proceeds remaining from the sale of Laurel Mountain after 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.

Table of Contents**Results of Operations**

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Percent Change	2012	2011	Percent Change
Pricing:						
Weighted Average Market Prices:						
NGL price per gallon Conway hub	\$ 0.70	\$ 1.13	(38.1)%	\$ 0.78	\$ 1.11	(29.7)%
NGL price per gallon Mt. Belvieu hub	0.86	1.36	(36.8)%	0.99	1.30	(23.8)%
Natural gas sales (\$/Mcf):						
Velma	2.64	4.02	(34.3)%	2.41	4.04	(40.3)%
WestOK	2.62	4.04	(35.1)%	2.43	4.05	(40.0)%
WestTX	2.54	4.05	(37.3)%	2.32	4.04	(42.6)%
Weighted Average	2.60	4.04	(35.6)%	2.39	4.04	(40.8)%
NGL sales (\$/gallon):						
Velma	0.73	1.16	(37.1)%	0.79	1.12	(29.5)%
WestOK	0.86	1.17	(26.5)%	0.86	1.13	(23.9)%
WestTX	0.96	1.42	(32.4)%	1.01	1.32	(23.5)%
Weighted Average	0.87	1.27	(31.5)%	0.90	1.21	(25.6)%
Condensate sales (\$/barrel):						
Velma	91.40	88.54	3.2%	96.93	94.39	2.7%
WestOK	82.06	81.23	1.0%	87.29	86.75	0.6%
WestTX	90.41	87.68	3.1%	90.81	92.77	(2.1)%
Weighted Average	86.65	85.77	1.0%	90.07	90.91	(0.9)%
Operating data:						
Velma system:						
Gathered gas volume (MCFD)	136,939	111,777	22.5%	134,248	101,593	32.1%
Processed gas volume (MCFD)	133,166	104,930	26.9%	128,398	95,643	34.2%
Residue gas volume (MCFD)	108,609	87,099	24.7%	105,135	78,462	34.0%
NGL volume (BPD)	14,866	12,198	21.9%	14,306	11,219	27.5%
Condensate volume (BPD)	283	346	(18.2)%	427	439	(2.7)%
WestOK system:						
Gathered gas volume (MCFD)	403,304	277,794	45.2%	346,318	260,863	32.8%
Processed gas volume (MCFD)	380,113	263,654	44.2%	326,337	247,259	32.0%
Residue gas volume (MCFD)	360,688	242,744	48.6%	302,486	224,158	34.9%
NGL volume (BPD)	12,998	13,392	(2.9)%	13,810	13,395	3.1%
Condensate volume (BPD)	1,341	786	70.6%	1,318	842	56.5%
WestTX system ⁽¹⁾ :						
Gathered gas volume (MCFD)	288,607	224,412	28.6%	268,456	205,089	30.9%
Processed gas volume (MCFD)	255,709	198,068	29.1%	241,710	188,292	28.4%
Residue gas volume (MCFD)	189,549	136,594	38.8%	172,150	128,584	33.9%
NGL volume (BPD)	28,499	27,387	4.1%	31,441	28,003	12.3%
Condensate volume (BPD)	2,132	2,257	(5.5)%	1,672	1,707	(2.1)%
Barnett system:						
Average throughput volumes (MCFD)	22,789		100.0%	23,084		100.0%
Tennessee system:						
Average throughput volumes (MCFD)	8,387	7,493	11.9%	8,320	7,747	7.4%
WTLPG system ⁽¹⁾ :						
Average NGL volumes (BPD)	256,579	227,822	12.6%	247,568	227,334	8.9%

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

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Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

The following table and discussion is a summary of our consolidated results of operations for the three months ended September 30, 2012 and 2011 (in thousands):

	Three Months Ended September 30,		Variance	Percent Change
	2012	2011 ⁽¹⁾		
<i>Gross margin</i> ⁽²⁾				
Natural gas and liquids sales	\$ 274,618	\$ 341,498	\$ (66,880)	(19.6)%
Transportation, processing and other fees	19,272	11,691	7,581	64.8%
Less: non-cash line fill gain (loss) ⁽³⁾	375	(422)	797	188.9%
Less: natural gas and liquids cost of sales	224,778	282,391	(57,613)	(20.4)%
Gross margin	68,737	71,220	(2,483)	(3.5)%
<i>Expenses:</i>				
Operating expenses	15,592	14,361	1,231	8.6%
General and administrative ⁽⁴⁾	12,123	9,149	2,974	32.5%
Depreciation and amortization	23,161	19,471	3,690	19.0%
Interest expense	9,692	5,935	3,757	63.3%
Total expenses	60,568	48,916	11,652	23.8%
<i>Other income items:</i>				
Derivative gain (loss), net ⁽¹⁾	(18,907)	23,760	(42,667)	(179.6)%
Other income, net ⁽¹⁾	2,585	2,831	(246)	(8.7)%
Non-cash line fill gain (loss) ⁽³⁾	375	(422)	797	188.9%
Equity income in joint ventures	1,422	1,785	(363)	(20.3)%
Income attributable to non-controlling interests ⁽⁵⁾	(1,511)	(1,760)	249	14.1%
Net income attributable to common limited partners and General Partner	\$ (7,867)	\$ 48,498	\$ (56,365)	(116.2)%
<i>Non-GAAP financial data:</i>				
EBITDA ⁽²⁾	\$ 24,986	\$ 73,904	\$ (48,918)	(66.2)%
Adjusted EBITDA ⁽²⁾	55,941	49,703	6,238	12.6%
Distributable cash flow ⁽²⁾	37,615	37,250	365	1.0%

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

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 September 30, 2012 decreased primarily due to lower natural gas and NGL sales prices partially offset by higher production volumes.

Volumes on the Velma system increased for the three months ended September 30, 2012 when compared to the prior year period primarily due to increased production gathered on the Madill-to-Velma gas gathering pipeline and the start-up of the

new Velma plant expansion in June 2012 (see Recent Events).

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Gathered and processed volumes on the WestOK system increased for the three months ended September 30, 2012 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand; and partially due to the start-up of the new Waynoka II plant in September 2012 (see [Recent Events](#)). NGL production volumes decreased for the three months ended September 30, 2012 compared to the prior year primarily due to ethane rejection throughout the quarter to avoid exceeding volume limits on the NGL pipeline.

Gathered and processed volumes on the WestTX system increased for the three months ended September 30, 2012 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. NGL volumes for the three months ended September 30, 2012 increased at a lower rate than processed volumes when compared to the prior year period due to reduced processing at a third-party fractionator in Mont Belvieu resulting in reduced NGL production during the quarter, including the rejection of ethane in order to meet reduced allocated NGL volumes. The fractionator returned to full operation in October 2012.

Transportation, processing and other fees for the three months ended September 30, 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; transportation and compression expenses; and other costs for the three months ended September 30, 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 September 30, 2012 mainly due to increased non-cash compensation expense 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 September 30, 2012 increased primarily due to expansion capital expenditures incurred subsequent to September 30, 2011.

Interest expense for the three months ended September 30, 2012 increased primarily due to (1) a \$3.1 million increase in interest expense associated with the 8.75% senior unsecured notes due on June 15, 2018 ([8.75% Senior Notes](#)); and (2) a \$1.0 million increase in interest associated with the revolving credit facility; partially offset by a \$0.5 million increase in capitalized interest. 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 subsequent to September 30, 2011 to cover current capital expenditures. The increased capitalized interest is due to the increased capital expenditures in the current period (see [Capital Requirements](#)).

Other income items:

Derivative gain (loss), net had an unfavorable variance for the three months ended September 30, 2012 mainly due to a \$49.4 million unfavorable variance on the fair value revaluation of commodity derivative contracts between the current period and the prior year period as a result of commodity prices

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rising in the current quarter and falling in the prior year comparable period; offset by a \$6.8 million favorable variance for realized settlements in the current period mainly as a result of lower NGL prices. While we utilize either quoted market prices or observable market data to calculate the fair value of natural gas and crude oil derivatives, valuations of NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGLs for similar geographic locations, and valuations of NGL options are based on forward price curves developed by third-party financial institutions. The use of unobservable market data for NGL fixed price swaps and NGL options has no impact on the settlement of these derivatives. However, a change in management's estimated fair values for these derivatives could impact net income, although it would have no impact on liquidity or capital resources (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 9 for further discussion of derivative instrument valuations). We recognized a \$11.2 million mark-to-market loss and a \$5.9 million mark-to-market gain on derivatives, which are valued based upon unobservable inputs, for the three months ended September 30, 2012 and 2011, respectively. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3: Quantitative and Qualitative Disclosures About Market Risk.

Other income, net for the three months ended September 30, 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 former 49% non-controlling ownership interest in Laurel Mountain, which we sold in February 2011.

Non-cash line fill gain (loss) had a favorable variance for the three months ended September 30, 2012 compared to the prior year period primarily due to a gain recognized on the revaluation of line fill in the current period due to increased NGL prices during the period; and a loss recognized in the prior year period due to decreased NGL prices during the prior year period.

Equity income in joint ventures decreased for the three months ended September 30, 2012 compared to the prior year period due to depreciation expense recorded in the current period related to the fair value of our 20% ownership interest in the property plant and equipment of WTLPG, which was in excess of book value at the time of acquisition.

Income attributable to non-controlling interests decreased primarily due to lower net income for the WestTX joint venture, which was formed to accomplish our acquisition of control of the system. The decrease in net income of the joint venture was principally due to lower gross margins on the sale of commodities, resulting from lower prices. The non-controlling interest expense represents Anadarko Petroleum Corporation's interest in the net income of the WestOK and WestTX joint ventures.

Non-GAAP financial data:

EBITDA was lower for the three months ended September 30, 2012 compared to the prior year period mainly due to the unfavorable derivative gain (loss) variance, as discussed above in Other income items; higher general and administrative expenses, as discussed above in Expenses; and lower gross margin, as discussed above in Gross margin.

Adjusted EBITDA had a favorable variance for the three months ended September 30, 2012 compared to the prior year period mainly due to the favorable variance of the cash portion of the derivative gain, as discussed above in Other income items; and a \$1.0 million favorable variance on distributions received from joint ventures during the three months ended September 30, 2012 compared to the prior year period; partially offset by a lower gross margin variance, as discussed above in Gross margin.

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Distributable cash flow had a favorable variance for the three months ended September 30, 2012 compared to the prior year period due to the favorable variance of Adjusted EBITDA, partially offset by higher interest expense, as discussed above in Expenses ; and higher premiums paid for derivative options in the current period compared to the prior year period.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The following table and discussion is a summary of our consolidated results of operations for the nine months ended September 30, 2012 and 2011 (in thousands):

	Nine Months Ended September 30,			Percent Change
	2012	2011⁽¹⁾	Variance	
<i>Gross margin⁽²⁾</i>				
Natural gas and liquids sales	\$ 802,644	\$ 937,975	\$ (135,331)	(14.4)%
Transportation, processing and other fees	46,831	31,536	15,295	48.5%
Less: non-cash line fill gain (loss) ⁽³⁾	(2,120)	(665)	(1,455)	(218.8)%
Less: natural gas and liquids cost of sales	652,986	774,859	(121,873)	(15.7)%
Gross margin	198,609	195,317	3,292	1.7%
<i>Expenses:</i>				
Operating expenses	44,354	41,426	2,928	7.1%
General and administrative ⁽⁴⁾	32,513	26,821	5,692	21.2%
Depreciation and amortization	65,715	57,499	8,216	14.3%
Interest expense	27,669	24,525	3,144	12.8%
Total expenses	170,251	150,271	19,980	13.3%
<i>Other income items:</i>				
Derivative gain (loss), net ⁽¹⁾	36,905	8,952	27,953	312.3%
Other income, net ⁽¹⁾	7,588	8,365	(777)	(9.3)%
Non-cash line fill gain (loss) ⁽³⁾	(2,120)	(665)	(1,455)	(218.8)%
Equity income in joint ventures	4,235	2,934	1,301	44.3%
Gain on asset sales and other ⁽⁵⁾		255,593	(255,593)	(100.0)%
Loss on early extinguishment of debt		(19,574)	19,574	100.0%
Income attributable to non-controlling interests ⁽⁶⁾	(4,108)	(4,492)	384	8.5%
Preferred unit dividends		(389)	389	100.0%
Net income attributable to common limited partners and General Partner	\$ 70,858	\$ 295,770	\$ (224,912)	(76.0)%
<i>Non-GAAP financial data:</i>				
EBITDA ⁽²⁾	\$ 164,242	\$ 378,183	\$ (213,941)	(56.6)%
Adjusted EBITDA ⁽²⁾	156,088	131,787	24,301	18.4%
Distributable cash flow ⁽²⁾	105,639	93,895	11,744	12.5%

(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.

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Gross margin:

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the nine months ended September 30, 2012 decreased primarily due to lower natural gas and NGL sales prices partially offset by higher production volumes.

Volumes on the Velma system increased for the nine months ended September 30, 2012 compared to the prior year period primarily due to increased production gathered on the Madill-to-Velma gas gathering pipeline and the start-up of the Velma expansion plant in June 2012.

Volumes on the WestOK system increased for the nine months ended September 30, 2012 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand.

WestTX system gathering and processing volumes for the nine months ended September 30, 2012 increased compared to the prior year period due to increased volumes from Pioneer Natural Resources Company (NYSE: PXD) as a result of their continued drilling program.

Transportation, processing and other fees for the nine months ended September 30, 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; transportation and compression expenses; and other costs, for the nine months ended September 30, 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 nine months ended September 30, 2012 mainly due to increased non-cash compensation expense 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 nine months ended September 30, 2012 increased primarily due to expansion capital expenditures incurred subsequent to September 30, 2011.

Interest expense for the nine months ended September 30, 2012 increased primarily due to a \$9.1 million increase in interest expense associated with the 8.75% Senior Notes; and a \$3.2 million increase in interest associated with the revolving credit facility; partially offset by a \$6.0 million decrease in interest expense associated with the 8.125% Senior Notes; and a \$3.3 million increase in capitalized interest. The increased interest expense on the 8.75% Senior Notes is due to the issuance of additional 8.75% Senior Notes in November 2011. The increased interest expense associated with the revolving credit facility is due to additional borrowings since September 30, 2011 to cover capital expenditures. 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).

Table of Contents*Other income items:*

Derivative gain (loss), net had a favorable variance for the nine months ended September 30, 2012 mainly due to an \$18.5 million favorable variance for realized settlements in the current period compared to the prior year period mainly as a result of lower NGL prices; combined with a \$9.5 million favorable variance on the fair value revaluation of commodity derivative contracts in the current period compared to the prior year period. While we utilize either quoted market prices or observable market data to calculate the fair value of natural gas and crude oil derivatives, valuations of NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGLs for similar geographic locations, and valuations of NGL options are based on forward price curves developed by third-party financial institutions. The use of unobservable market data for NGL fixed price swaps and NGL options has no impact on the settlement of these derivatives. However, a change in management's estimated fair values for these derivatives could impact net income, although it would have no impact on liquidity or capital resources (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 9 for further discussion of derivative instrument valuations). We recognized a \$33.2 million mark-to-market gain and a \$6.4 million mark-to-market loss for derivatives, which were valued upon unobservable inputs, for the nine months ended September 30, 2012 and 2011, respectively. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3: Quantitative and Qualitative Disclosures About Market Risk.

Other income, net for the nine months ended September 30, 2012 decreased compared to the prior year period primarily due to lower interest income, which is partially due to the December 2011 settlement of a note receivable from The Williams Companies, Inc. (NYSE: WMB) related to our former 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 nine months ended September 30, 2012 compared to the prior year period primarily due to an increased loss recognized on the revaluation of line fill due to decreased NGL prices.

Equity income in joint ventures increased for the nine months ended September 30, 2012 primarily due to a full nine months of equity earnings generated in the current period from our 20% ownership interest in WTPLG compared to equity earnings for only a portion of the prior year period due to the purchase of our ownership interest in May 2011.

Gain on asset sales and other for the nine months ended September 30, 2011 includes amounts associated with the sale of our 49% interest in Laurel Mountain on February 17, 2011.

Preferred unit dividends for the nine months ended September 30, 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 nine months ended September 30, 2012 compared to the prior year period mainly due to the gain on sale of assets recognized during the nine months ended September 30, 2011, as discussed above in Other income items; partially offset by the favorable derivative gain recognized during the nine months ended September 30, 2011, as discussed above in Other income items; and the impact of the loss on early extinguishment of debt recorded in the prior year period as discussed above in Other income items.

Adjusted EBITDA had a favorable variance for the nine months ended September 30, 2012 compared to the prior year period partially due to the favorable variance of the cash portion of the

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derivative gain, as discussed above in **Other income items** ; a higher gross margin variance, as discussed above in **Gross margin** ; and a \$2.9 million higher distribution received from joint ventures during the nine months ended September 30, 2012 compared to the prior year period.

Distributable cash flow had a favorable variance for the nine months ended September 30, 2012 compared to the prior year period due to the favorable variance of Adjusted EBITDA, partially offset by \$5.9 million net proceeds in the prior year period, which was remaining from the sale of Laurel Mountain after repayment of debt; higher interest expense, as discussed above in **Expenses** ; and higher premiums paid for derivative options in the current period compared to the prior year period.

Liquidity and Capital Resources

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

cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;

expansion capital expenditures and working capital deficits through the retention of cash and additional capital raising; and

debt principal payments through operating cash flows and refinancings as they become due, or by the issuance of additional limited partner units or asset sales.

At September 30, 2012, we had \$80.0 million outstanding borrowings under our \$600.0 million senior secured revolving credit facility and \$0.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with \$519.9 million remaining committed capacity under the revolving credit facility, (see **Revolving Credit Facility**). We were in compliance with the credit facility's covenants at September 30, 2012. We had a working capital deficit of \$40.5 million at September 30, 2012 compared with \$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.

Table of Contents*Cash Flows Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011*

The following table details the cash flow changes between the nine months ended September 30, 2012 and 2011 (in thousands):

	Nine Months Ended September 30,		Variance	Percent Change
	2012	2011		
Net cash provided by (used in):				
Operating activities	\$ 125,523	\$ 80,658	\$ 44,865	55.6%
Investing activities	(278,725)	165,994	(444,719)	(267.9)%
Financing activities	153,199	(246,649)	399,848	162.1%
Net change in cash and cash equivalents	\$ (3)	\$ 3	\$ (6)	

Net cash provided by operating activities for the nine months ended September 30, 2012 increased compared to the prior year period due to a \$45.4 million increase in net earnings from continuing operations excluding non-cash charges. The increase is primarily due to favorable transportation, processing and other fees from increased gathered and processed volumes; favorable derivative settlements in the current period compared to the prior year period; and increased distributions received from WTLPG (see Results of Operations).

Net cash provided by (used in) investing activities for the nine months ended September 30, 2012 had an unfavorable variance compared to the prior year period mainly due to (1) net proceeds of \$411.5 million received from the sale of Laurel Mountain in the prior period; (2) a \$94.3 million increase in capital expenditures in the current year period compared to the prior year period (see further discussion of capital expenditures under Capital Requirements); and (3) \$36.7 million cash paid for acquisition of assets in the current period, partially offset by \$85.0 million paid to acquire the interest in WTLPG in the prior year period and \$12.3 million cash paid in capital contributions to Laurel Mountain in the prior year period.

Net cash provided by (used in) financing activities for the nine months ended September 30, 2012 had a favorable variance compared to the prior year period mainly due to \$319.1 million of net proceeds received in the current period from the issuance of our new 6.625% Senior Notes (see Recent Events); and \$293.9 million used in the prior year period to redeem the 8.125% Senior Notes and a portion of the 8.75% Senior Notes; partially offset by \$128.5 million provided by additional borrowings on our revolving credit facility in the prior year period for capital expenditures; \$62.0 million used to reduce outstanding borrowings on the revolving credit facility in the current period; and \$28.1 million increased distributions paid in the current year compared to the prior year period. The gross amount of borrowings and repayments under the revolving credit facility included within net cash provided by (used in) financing activities in the consolidated combined statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of (i) cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under the revolving credit facility, and (ii) payments, which generally occur throughout the period and increase borrowings under the revolving credit facility, which is generally common practice for the industry.

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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Expansion capital expenditures	\$ 91,292	\$ 51,195	\$ 229,170	\$ 134,693
Maintenance capital expenditures	4,732	4,980	13,242	13,451
Total	\$ 96,024	\$ 56,175	\$ 242,412	\$ 148,144

Expansion capital expenditures increased for the three and nine months ended September 30, 2012 compared to the prior year periods primarily due to current major processing facility expansions, compressor upgrades and pipeline projects, including the 60 MMCFD expansion at the Velma system, which was placed in service in June 2012; a 200 MMCFD expansion at the WestOK system, placed in service in September 2012; and construction of a 100 MMCFD plant in the WestTX system scheduled to be placed in service in the first half of 2013. As of September 30, 2012, we had approved additional expenditures of approximately \$220.5 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately \$133.0 million purchase commitments had been made. We expect to fund these projects through operating cash flows and borrowings under our existing revolving credit facility.

Partnership Distributions

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

Our General Partner is granted discretion by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When our General Partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 2% of the aggregate amount of cash being distributed. Our General Partner, holder of all our incentive distribution rights, has agreed to allocate up to \$3.75 million of its incentive distribution rights per quarter back to us after the General Partner receives the initial \$7.0 million of incentive distribution rights per quarter. Incentive distributions of \$1.6 million and \$0.4 million were paid during the three months ended September 30, 2012 and 2011, respectively, and \$4.5 million and \$0.4 million were paid during the nine months ended September 30, 2012 and 2011, respectively.

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Off Balance Sheet Arrangements

As of September 30, 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 September 30, 2012, we had a \$600.0 million senior secured revolving credit facility with a syndicate of banks, which matures in May 2017. Borrowings under the revolving credit facility bear interest, at our option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at September 30, 2012, was 2.5%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$0.1 million was outstanding at September 30, 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 September 30, 2012, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

At September 30, 2012, we had \$370.4 million principal amount outstanding of 8.75% Senior Notes and \$325.0 million principal amount outstanding of 6.625% Senior Notes (collectively, the Senior Notes).

The 8.75% Senior Notes are presented combined with a net \$4.6 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.

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On April 7, 2011, we redeemed \$7.2 million of the 8.75% Senior Notes, which were tendered upon our offer to purchase the 8.75% Senior Notes, at par. The sale of our 49% non-controlling interest in Laurel Mountain on February 17, 2011 constituted an Asset Sale pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, we offered to purchase any and all of the 8.75% Senior Notes.

On April 8, 2011, we redeemed all the 8.125% Senior Notes. 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. We paid \$293.7 million to redeem the \$275.5 million principal plus \$11.2 million premium and \$7.0 million accrued interest. In addition, we recorded \$5.2 million related to accelerated amortization of deferred financing costs associated with the retirement of the 8.125% Senior Notes and a partial redemption of the 8.75% Senior Notes.

On September 28, 2012, we issued \$325.0 million of the 6.625% Senior Notes, at par, in a private placement transaction. We received net proceeds of \$319.1 million and utilized the proceeds to reduce the outstanding balance on our revolving credit facility. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest at the date of redemption.

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

Indentures governing the Senior Notes contain covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all our assets. We were in compliance with these covenants as of September 30, 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 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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	Effect if	Actual Results Differ from
Description	Judgments and Uncertainties	Estimates and Assumptions
<p><u><i>Acquisitions Purchase Price Allocation</i></u> 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.</p>	<p>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.</p>	<p>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.</p>
<p><u><i>Impairment of Long-Lived Assets</i></u> Management evaluates our long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. A long-lived asset is considered impaired when the estimated undiscounted cash flow from such asset is less than the asset's carrying value. In that event, a loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset. Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions.</p>	<p>In evaluating impairment, management considers the use or disposition of an asset, the estimated remaining life of an asset, and future expenditures to maintain an asset's existing service potential. In order to determine the cash flow, management must make certain estimates and assumptions, which include, but are not limited to, changes in general economic conditions in regions in which we operate, our ability to negotiate favorable contracts, the risks that natural gas exploration and production activities will not occur or be successful, competition from other midstream companies, our dependence on certain significant customers and producers of natural gas, and the volume of reserves behind an asset and future NGL product and natural gas prices.</p>	<p>As of September 30, 2012, there were no indicators of impairment for any of our assets. A significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset. Recent increases in natural gas drilling has driven an increase in the supply of natural gas and put a downward pressure on domestic prices. Further declines in natural gas and NGL prices may result in impairment charges in future periods.</p>

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Description	Judgments and Uncertainties	Effect if
		Actual Results Differ from
		Estimates and Assumptions
<p><u>Derivative Instruments</u></p> <p>Our derivative financial instruments are recorded at fair value in the consolidated balance sheets. Changes in fair value and settlements are reflected in our earnings in the consolidated statements of operations as gains and losses related to natural gas liquids sales, interest expense and/or derivative loss, net. (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 9 for further discussion)</p>	<p>When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument's fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based upon inputs that are largely unobservable. These instruments are classified as Level 3 under the fair value hierarchy. The fair value of these instruments are determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.</p>	<p>If the assumptions used in the pricing models for our financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains that could be material. Of the \$43.4 million and \$16.5 million net derivative assets at September 30, 2012 and December 31, 2011, respectively, we had \$35.4 million and \$16.5 million net derivative assets at September 30, 2012 and December 31, 2011, respectively, that were classified as Level 3 fair value measurements, which rely on subjective forward developed price curves. Holding all other variables constant, a 10% change in the prices utilized in calculating the Level 3 fair value of derivatives at September 30, 2012 would have resulted in a \$9.9 million noncash change to net income for the nine months ended September 30, 2012.</p>

Recently Adopted Accounting Standards

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.

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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 September 30, 2012. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

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

Interest Rate Risk. At September 30, 2012, we had a \$600.0 million senior secured revolving credit facility with \$80.0 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 2.5% at September 30, 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 \$0.8 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 8 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 October 4, 2012, were \$0.90 per gallon, \$3.71 per million BTU and \$92.93 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended September 30, 2013 by approximately \$8.4 million.

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ITEM 4. CONTROLS AND PROCEDURES

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

Under the supervision of our General Partner's Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner's Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 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⁾
4.3	Registration Rights Agreement, dated May 16, 2012, between Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein. ⁽²⁷⁾
4.4	6 5/8% Senior Notes Indenture dated September 28, 2012. ⁽²⁸⁾
4.5	Registration Rights Agreement, dated September 28, 2012, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein. ⁽²⁸⁾
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⁾

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- 10.3(b) Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011⁽²²⁾
- 10.3(c) Incremental Joinder Agreement to the Amended and Restated Credit Agreement dated as of July 8, 2011⁽²³⁾
- 10.3(d) Amendment No. 2 to the Amended and Restated Credit Agreement dated as of May 31, 2012⁽²⁶⁾

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- 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⁾
- 10.8 Form of 2004 Long-Term Incentive Plan Phantom Unit Grant Letter
- 10.9 Form of Grant of Phantom Units to Non-Employee Managers⁽¹¹⁾
- 10.10 Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan⁽¹⁰⁾
- 10.11 Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement⁽¹⁰⁾
- 10.12 Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010⁽¹³⁾

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Exhibit No.	Description
10.13	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010 ⁽²⁰⁾
10.14	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010 ⁽²⁰⁾
10.15	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011 ⁽²⁴⁾
10.16	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011 ⁽²⁴⁾
10.17	Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011 ⁽²¹⁾
10.18	Employment Agreement between Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Patrick J. McDonie dated as of July 3, 2012 ⁽²⁷⁾
10.19	Purchase Agreement dated September 25, 2012 by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries listed therein, and Wells Fargo Securities, LLC, on behalf of itself and the other initial purchasers. ⁽²⁸⁾
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 ⁽²⁹⁾
101.SCH	XBRL Schema Document ⁽²⁹⁾
101.CAL	XBRL Calculation Linkbase Document ⁽²⁹⁾
101.LAB	XBRL Label Linkbase Document ⁽²⁹⁾
101.PRE	XBRL Presentation Linkbase Document ⁽²⁹⁾
101.DEF	XBRL Definition Linkbase Document ⁽²⁹⁾

- (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) [Intentionally omitted]
- (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.

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- (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) Previously filed as an exhibit to current report on Form 8-K filed on May 31, 2012.
- (27) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2012.
- (28) Previously filed as an exhibit to current report on Form 8-K filed on September 28, 2012.
- (29) 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: November 5, 2012

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

Date: November 5, 2012

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