ATLAS PIPELINE PARTNERS LP
Form 10-Q
May 07, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2010

OR

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

For the transition period from ______ to ______

Commission file number: 1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1550 Coraopolis Heights Road Moon Township, Pennsylvania	**15108**
(Address of principal executive office)	**(Zip code)**

Registrant s telephone number, including area code: (412) 262-2830

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

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

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

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

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

The number of common units of the registrant outstanding on May 4, 2010 was 53,211,498.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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ON FORM 10-Q

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	March 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 159	$ 1,021
Accounts receivable	69,853	100,721
Current portion of derivative asset	635	998
Prepaid expenses and other	15,586	15,404
Total current assets	86,233	118,144
Property, plant and equipment, net	1,679,472	1,684,384
Intangible assets, net	161,702	168,091
Investment in joint venture	130,461	132,990
Long-term portion of derivative asset		361
Other assets, net	32,689	33,993
	$ 2,090,557	$ 2,137,963
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 590	$
Accounts payable affiliates	5,012	2,043
Accounts payable	12,080	22,928
Accrued liabilities	16,431	14,348
Accrued interest payable	16,556	9,652
Current portion of derivative liability	13,311	33,547
Accrued producer liabilities	65,621	66,211
Total current liabilities	129,601	148,729
Long-term portion of derivative liability	7,893	11,126
Long-term debt, less current portion	1,202,808	1,254,183
Other long-term liability	355	398
Commitments and contingencies		
Partners capital:		
Class B preferred limited partner s interest	14,955	14,955
Common limited partners interests	803,839	787,834

Investment in Class B cumulative preferred member units of Atlas Pipeline Holdings II, LLC (reported as treasury units)	(15,000)	(15,000)
General partner s interest	15,864	15,853
Accumulated other comprehensive loss	(38,472)	(49,190)
	781,186	754,452
Non-controlling interest	(31,286)	(30,925)
Total partners capital	749,900	723,527
	$ 2,090,557	$ 2,137,963

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Revenue:		
Natural gas and liquids	$ 260,949	$ 144,133
Transportation, compression, processing and other fees affiliates	176	10,068
Transportation, compression, processing and other fees third parties	14,079	14,891
Equity income in joint venture	1,462	
Other income, net	6,569	5,149
Total revenue and other income, net	283,235	174,241
Costs and expenses:		
Natural gas and liquids	206,663	134,745
Plant operating	15,534	13,823
Transportation and compression	189	3,331
General and administrative	9,419	10,303
Compensation reimbursement affiliates	375	375
Depreciation and amortization	22,746	22,668
Interest	26,431	21,108
Total costs and expenses	281,357	206,353
Income (loss) from continuing operations	1,878	(32,112)
Income from discontinued operations		8,876
Net income (loss)	1,878	(23,236)
Income attributable to non-controlling interests	(1,317)	(469)
Preferred unit dividends		(900)
Net income (loss) attributable to common limited partners and the general partner	$ 561	$ (24,605)

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Allocation of net income (loss) attributable to common limited partners and the general partner:		
Common limited partners interest:		
Continuing operations	$ 550	$ (32,808)
Discontinued operations		8,698
	550	(24,110)
General Partner s interest:		
Continuing operations	11	(673)
Discontinued operations		178
	11	(495)
Net income (loss) attributable to common limited partners and the General Partner:		
Continuing operations	561	(33,481)
Discontinued operations		8,876
	561	$ (24,605)
Net income (loss) attributable to common limited partners per unit:		
Basic:		
Continuing operations	$ 0.01	$ (0.71)
Discontinued operations		0.19
	0.01	$ (0.52)
Diluted:		
Continuing operations	$ 0.01	$ (0.71)
Discontinued operations		0.19
	0.01	$ (0.52)
Weighted average common limited partner units outstanding:		
Basic	52,849	45,971
Diluted	52,950	45,971

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE THREE MONTHS ENDED MARCH 31, 2010

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units								
	Class B Preferred	Common	Class B Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive (Loss)	Class B Preferred Units of Atlas Pipeline Holdings II, LLC	Non-controlling Interest	Partners Capital
Balance at January 1, 2010	15,000	50,517,103	$ 14,955	$ 787,834	$ 15,853	$ (49,190)	$ (15,000)	$ (30,925)	$ 723,527
Issuance of common units		2,689,765		15,332					15,332
Distributions to non-controlling interests								(1,678)	(1,678)
Issuance of units under incentive plans		2,866		123					123
Other comprehensive income						10,718			10,718
Net income				550	11			1,317	1,878
Balance at March 31, 2010	15,000	53,209,734	$ 14,955	$ 803,839	$ 15,864	$ (38,472)	$ (15,000)	$ (31,286)	$ 749,900

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Three Months Ended March 31, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 1,878	$ (23,236)
Less: Income from discontinued operations		8,876
Net income (loss) from continuing operations	1,878	(32,112)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	22,746	22,668
Equity income in joint venture	(1,462)	
Distributions received from joint venture	3,991	
Non-cash compensation expense (income)	123	(93)
Amortization of deferred finance costs	1,623	1,017
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable, prepaid expenses and other	30,686	26,228
Accounts payable and accrued liabilities	(3,025)	(23,210)
Derivative accounts payable and receivable	(12,027)	43,885
Accounts payable and accounts receivable affiliates	2,969	12,937
Net cash provided by continuing operations	47,502	51,320
Net cash provided by discontinued operations		12,411
Net cash provided by operations	47,502	63,731
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(10,914)	(72,196)
Other	(319)	(159)
Net cash used in continuing investing activities	(11,233)	(72,355)
Net cash used in discontinued investing activities		(651)
Net cash used in investing activities	(11,233)	(73,006)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	137,000	158,000
Repayments under credit facility	(183,000)	(136,000)
Repayment of debt	(7,661)	
Principal payments on capital lease	(94)	
Net proceeds from issuance of common limited partner units	15,332	
Net proceeds from issuance of Class B preferred limited partner units		4,961
General partner capital contributions		308
Distributions paid to common limited partners, the general partner and preferred limited partners		(18,153)
Net distributions to non-controlling interest holders	(1,678)	710
Other	2,970	(159)

Net cash provided by (used in) financing activities	(37,131)	9,667
Net change in cash and cash equivalents	(862)	392
Cash and cash equivalents, beginning of period	1,021	1,445
Cash and cash equivalents, end of period	$ 159	$ 1,837

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

MARCH 31, 2010

(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. 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. Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 1.9% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98.1% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 5,754,253 common limited partner units in the Partnership and 15,000 $1,000 par value Class B preferred limited partner units. At March 31, 2010, the Partnership had 53,209,734 common limited partnership units outstanding, including the 5,754,253 common units held by the General Partner, plus the 15,000 $1,000 par value Class B preferred units held by the General Partner.

On March 31, 2010, the Partnership s partnership agreement was amended to provide a temporary waiver of a capital contribution required for the General Partner to maintain its 2.0% general partner interest in the Partnership, relative to the January 2010 issuance of common units for warrants exercised. The General Partner will not be required to make such capital contribution until it has received aggregate distributions from the Partnership, beginning with the first quarter of 2010, sufficient to fund the required capital contribution. During this waiver period the General Partner s general partner interest will be reduced by approximately 0.1% (see Note 5).

The General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas Energy, Inc. and its affiliates (Atlas Energy), a publicly-traded company (NASDAQ: ATLS), at March 31, 2010, owned a 64.3% ownership interest in AHD s common units and 1,112,000 of the Partnership s common limited partnership units, representing a 2.1% ownership interest in the Partnership.

The majority of the natural gas that the Partnership and its affiliates, including Laurel Mountain Midstream, LLC (Laurel Mountain), gather in Appalachia is derived from wells operated by Atlas Energy. Laurel Mountain, which was formed in May 2009, is a joint venture between the Partnership and The Williams Companies, Inc. (NYSE: WMB) (Williams) in which the Partnership has a 49% ownership interest and Williams holds the remaining 51% ownership interest.

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-Q from the amounts previously presented to reflect the following items:

- In May 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system (NOARK) (see Note 4). The Partnership has retrospectively adjusted its prior period consolidated financial statements to reflect the amounts related to the operations of NOARK as discontinued operations; and

- On January 1, 2010, the Partnership reclassified a portion of its income, within its consolidated statements of operations, to Transportation, Compression, Processing and Other Fees for fee-based revenues which were previously reported within Natural Gas and Liquids . This reclassification was made in order to provide clarity between the revenue that is commodity based and the revenue that is fee-based.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2009 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, 2009. The results of operations for the three month period ended March 31, 2010 may not necessarily be indicative of the results of operations for the full year ending December 31, 2010. Certain amounts in the prior year s consolidated financial statements have been reclassified to conform to the current year presentation.

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, 2009.

Principles of Consolidation and Non-Controlling Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership s wholly-owned and majority-owned subsidiaries. The General Partner s interest in the Operating Partnership is reported as part of its overall 1.9% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

The Partnership s consolidated financial statements also include its 95% ownership interest in joint ventures which individually own a 100% ownership interest in the Chaney Dell natural gas gathering system and processing plants and a 72.8% undivided interest in the Midkiff/Benedum natural gas gathering system and processing plants. The Partnership consolidates 100% of these joint ventures and reflects the non-controlling 5% ownership interest in the joint ventures as non-controlling interests on its statements of operations. The Partnership also reflects the 5% ownership interest in the net assets of the joint ventures as non-controlling interests and as a component of partners capital on its consolidated balance sheets. The joint ventures have a $1.9 billion note receivable from the holder of the 5% ownership interest in the joint ventures, which is reflected within non-controlling interests on the Partnership s consolidated balance sheets.

The Midkiff/Benedum joint venture has a 72.8% undivided joint venture interest in the Midkiff/Benedum system, of which the remaining 27.2% interest is owned by Pioneer Natural Resources Company (NYSE: PXD) (Pioneer). Due to the Midkiff/Benedum system s status as an undivided joint venture, the Midkiff/Benedum joint venture proportionally consolidates its 72.8% ownership interest in the assets and liabilities and operating results of the Midkiff/Benedum system.

Equity Method Investments

The Partnership s consolidated financial statements include its 49% ownership interest in Laurel Mountain, a joint venture which owns and operates the Partnership s former Appalachia Basin natural gas gathering systems, excluding the Partnership s northeastern Tennessee operations. The Partnership accounts for its investment in the joint venture under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint venture s net income (loss) as equity income on its consolidated statements of operations.

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Use of Estimates

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

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented represent actual results in all material respects (see -Revenue Recognition accounting policy for further description).

Receivables

In evaluating the realizability of its accounts receivable, the Partnership performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by the Partnership s review of its customers credit information. The Partnership extends credit on an unsecured basis to many of its customers. At March 31, 2010 and December 31, 2009, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 7.4% and 4.8% for the three months ended March 31, 2010 and 2009, respectively. The amount of interest capitalized was $0.2 million and $1.4 million for the three months ended March 31, 2010 and 2009, respectively.

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at March 31, 2010 and December 31, 2009 (in thousands):

	March 31, 2010	December 31, 2009	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,810	$ 12,810	8
Customer relationships	222,572	222,572	7 20
	$ 235,382	$ 235,382	
Accumulated Amortization:			
Customer contracts	$ (7,794)	$ (7,397)	
Customer relationships	(65,886)	(59,894)	
	$ (73,680)	$ (67,291)	
Net Carrying Amount:			
Customer contracts	$ 5,016	$ 5,413	
Customer relationships	156,686	162,678	

	$ 161,702	$ 168,091

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. Amortization expense on intangible assets was $6.4 million for both the three months ended March 31, 2010 and 2009. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2010 to 2012 - $25.6 million; 2013 - $24.5 million; 2014 - $20.4 million.

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners, which is determined after the deduction of net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner s and the preferred unitholder s interests, by the weighted average number of common limited partner units outstanding during the period. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its 1.9% interest and incentive distributions to be distributed for the quarter (see Note 6), 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,

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management of the Partnership believes that the partnership agreement contractually limits cash distributions to available cash and, 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 plan 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. As such, the net income (loss) utilized in the calculation of net income (loss) per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net income (loss) 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, except per unit data):

	Three Months Ended March 31,	
	2010	2009[1]
Continuing operations:		
Net income (loss)	$ 1,878	$ (32,112)
Income attributable to non-controlling interest	(1,317)	(469)
Preferred unit dividends		(900)
Net income (loss) attributable to common limited partners and the general partner	561	(33,481)
General partner s actual 1.9% ownership interest	11	(673)
Net income (loss) attributable to common limited partners	550	(32,808)
Less: net income attributable to participating securities phantom units[2]	1	
Net income (loss) utilized in the calculation of net loss attributable to common limited partners per unit	$ 549	$ (32,808)
Discontinued operations:		
Net income	$	$ 8,698
Net income attributable to the general partner s ownership interests (1.9% ownership interest)		178
Net income utilized in the calculation of net income from discontinued operations attributable to common limited partners per unit	$	$ 8,876

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of the NOARK gas gathering and intrastate pipeline system (see Note 4).

(2) Net income attributable to common limited partners ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended March 31, 2009, net loss attributable to common limited partners ownership interest is not allocated to approximately 118,000 phantom units because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, 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 plan (see Note 13). The following table sets forth the reconciliation of the Partnership s weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Three Months Ended March 31,	
	2010	2009
Weighted average common limited partners per unit - basic	52,849	45,971
Add effect of participating securities phantom units(1)	51	
Add effect of dilutive option incentive awards(2)	50	
Add effect of dilutive convertible preferred limited partner units(3)		
Weighted average common limited partners per unit - diluted	52,950	45,971

(1) For the three months ended March 31, 2009, approximately 118,000 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.
(2) For the three months ended March 31, 2009, 100,000 unit options were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such unit options would have been anti-dilutive.
(3) For the three months ended March 31, 2009, potential common limited partner units issuable upon conversion of the Partnership s Class A cumulative convertible preferred limited partner units were excluded from the computation of diluted net loss attributable to common limited partners as the impact of the conversion would have been anti-dilutive. The Class B preferred limited partner units outstanding at March 31, 2010 were not convertible.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income (loss), are referred to as other comprehensive income (loss) or OCI and for the Partnership only include changes in the fair value of unsettled derivative contracts which were accounted for as cash flow hedges (see Note 9). The following table sets forth the calculation of the Partnership s comprehensive income (loss) (in thousands):

	Three Months Ended March 31,	
	2010	2009
Net income (loss)	$ 1,878	$ (23,236)
Income attributable to non-controlling interests	(1,317)	(469)
Preferred unit dividends		(900)
Net loss attributable to common limited partners and the general partner	561	(24,605)
Other comprehensive income:		
Changes in fair value of derivative instruments accounted for as hedges		(1,292)
Add: adjustment for realized losses reclassified to net loss	10,718	18,863
Total other comprehensive income	10,718	17,571
Comprehensive income (loss)	$ 11,279	$ (7,034)

Revenue Recognition

The Partnership s revenue primarily consists of the fees earned from its gathering and processing 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 natural gas liquids (NGLs), if any, off of 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 is recognized upon physical delivery of the natural gas. In connection with the Partnership s gathering and processing operations, it enters into the following types of contractual relationships with its producers and shippers:

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Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas. Revenue is a function of the volume of natural gas that the Partnership gathers and processes and is not directly dependent on the value of the natural gas. The Partnership is also paid a separate compression fee on many of its 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.

Percentage of Proceeds (POP) Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue natural 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. The volume of gas gathered or purchased is based on the measured volume at an agreed upon location (generally at the wellhead). The volume of gas redelivered or sold at the tailgate of the Partnership s processing facility will be lower than the volume purchased at the wellhead primarily due to British Thermal Units (BTUs) extracted when processed through a plant. The Partnership must make up or keep the producer whole for this loss in volume. 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 (i) the volume of residue gas available for redelivery to the producer may be less than received from the producer; or (ii) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under Keep-Whole agreements is often 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 of margin risk.

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 (see -Use of Estimates accounting policy for further description). The Partnership had unbilled revenues at March 31, 2010 and December 31, 2009 of $35.0 million and $65.4 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets.

Recently Adopted Accounting Standards

In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-06, Fair Value Measurements and Disclosures - Improving Disclosures about Fair Value Measurements, which provides enhanced disclosure requirements for activity in Levels 1, 2 and 3 fair value measurements. The update requires significant transfers in and out of Levels 1 and 2 fair value measurements to be reported separately and the reasons for such transfers to be disclosed. The update also requires information regarding purchases, sales, issuances, and settlements to be disclosed separately on a gross basis in the reconciliation of fair value measurements using unobservable inputs for all activity in Level 3 fair value measurements. Additionally, the update clarifies that fair value measurement for each class of assets and liabilities must be disclosed as well as disclosures pertaining to the inputs and valuation techniques for both recurring and nonrecurring fair value measurements in Levels 2 and 3. These requirements are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of

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activity in Level 3 fair value measurements. Those requirements will be effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The Partnership adopted these requirements on January 1, 2010 and it did not have a material impact on its financial position, results of operations or related disclosures.

NOTE 3 INVESTMENT IN JOINT VENTURE

On May 31, 2009, the Partnership and subsidiaries of Williams completed the formation of Laurel Mountain, a joint venture which owns and operates the Partnership s previously owned Appalachia natural gas gathering system, excluding the Partnership s northeastern Tennessee operations. Williams contributed cash and a note receivable of $25.5 million to the joint venture and owns 51% interest in Laurel Mountain. The Partnership contributed the Appalachia natural gas gathering system and owns a 49% interest in Laurel Mountain. The Partnership is also entitled to preferred distribution rights relating to all payments on the note receivable. Williams performs the day to day operations of the joint venture.

The Partnership recognizes its 49% ownership interest in Laurel Mountain as an investment in joint venture on its consolidated balance sheet at fair value. The Partnership accounts 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 on its consolidated statements of operations. As of March 31, 2010, the Partnership has utilized $8.5 million of the $25.5 million note receivable to make capital contributions to Laurel Mountain.

The following table provides the joint venture s summarized statement of operations for the three months ended March 31, 2010 and balance sheet data as of March 31, 2010 (in thousands):

	Three Months Ended March 31, 2010
Statement of Operations data:	
Total revenue	$ 11,084
Net income	2,645
	March 31, 2010
Balance Sheet data:	
Current assets	$ 14,009
Long-term assets	256,198
Current liabilities	13,551
Long-term liabilities	9,437
Net equity	247,219

NOTE 4 DISCONTINUED OPERATIONS

On May 4, 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE:SEP) (Spectra). The Partnership accounted for the earnings of the NOARK system assets as discontinued operations within its consolidated financial statements. The following table summarizes the components included within income from discontinued operations on the Partnership s consolidated statements of operations (in thousands):

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Total revenue and other income, net	$	$ 16,005
Total costs and expenses		(7,129)
Earnings of discontinued operations	$	$ 8,876

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NOTE 5 COMMON UNIT EQUITY OFFERINGS

In August 2009, the Partnership sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. The Partnership also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2% general partner interest in the Partnership. In addition, the Partnership issued warrants granting investors in its private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units.

On January 7, 2010, the Partnership executed amendments to the warrants originally issued in August 2009. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million to the Partnership. The Partnership utilized the net proceeds from the common unit offering to repay a portion of its indebtedness under its senior secured term loan (see Note 11) and to fund the early termination of certain derivative agreements (see Note 9).

The common units and warrants sold by the Partnership in the August 2009 private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement required the Partnership to (a) file a registration statement with the Securities and Exchange Commission for the privately placed common units and those underlying the warrants by September 21, 2009 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by November 18, 2009. The Partnership filed a registration statement with the Securities and Exchange Commission in satisfaction of the registration requirements of the registration rights agreement on September 3, 2009, and the registration statement was declared effective on October 14, 2009.

On March 31, 2010, the Partnership and the Operating Partnership amended their respective partnership agreements to temporarily waive the requirement that the General Partner make aggregate cash contributions of approximately $0.3 million, which was required in connection with the Partnership s issuance of 2,689,765 of its common units upon the exercise of certain warrants in January 2010. The waiver will remain in effect until the General Partner has received aggregate distributions from the Partnership sufficient to fund the required capital contribution. During the waiver period, the aggregate ownership percentage attributable to General Partner s general partner interest in the Partnership is reduced to 1.9%. Both amendments were approved by the Partnership s conflicts committee and managing board, and are effective as of January 11, 2010.

NOTE 6 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of 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. Common unit and General Partner distributions declared by the Partnership for the period from January 1, 2009 through March 31, 2010 were as follows:

Date Cash Distribution Paid	For Quarter Ended	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)
February 13, 2009	December 31, 2008	$ 0.38	$ 17,463	$ 358
May 15, 2009	March 31, 2009	$ 0.15	$ 7,149	$ 147

The Partnership did not declare cash distributions for the quarters ended June 30, 2009 through March 31, 2010.

NOTE 7 PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2010	December 31, 2009	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,668,645	$ 1,658,282	2 40
Rights of way	167,545	167,048	20 40
Buildings	8,920	8,920	40
Furniture and equipment	9,792	9,538	3 7
Other	13,142	12,849	3 10
	1,868,044	1,856,637	
Less accumulated depreciation	(188,572)	(172,253)	
	$ 1,679,472	$ 1,684,384	

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 are expensed as incurred. Major renewals and improvements that extend the useful lives of property 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.

Leased property and equipment meeting capital lease criteria are capitalized at the original cost of the equipment and are included within property plant and equipment. Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets.

NOTE 8 OTHER ASSETS

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

	March 31, 2010	December 31, 2009
Deferred finance costs, net of accumulated amortization of $26,937 and $25,314 at March 31, 2010 and December 31, 2009, respectively	$ 25,709	$ 27,331
Long-term pipeline lease prepayment	3,731	3,168
Security deposits	3,249	3,494
	$ 32,689	$ 33,993

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Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 11). Total amortization expense of deferred finance costs was $1.6 million and $1.0 million for the three months ended March 31, 2010 and 2009, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations. Amortization expense related to deferred finance costs is estimated to be as follows for each of the next five calendar years: 2010 to 2012 - $6.2 million; 2013 - $4.4 million; 2014 - $1.7 million.

NOTE 9 DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps and options, in connection with its commodity price and interest rate risk management activities. The Partnership enters into financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. It also enters into financial swap instruments to hedge certain portions of its floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. Under its swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period.

On July 1, 2008, the Partnership discontinued hedge accounting for all of its existing commodity derivatives which were previously qualified as hedges. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income, net in its consolidated statements of operations. The fair value of these commodity derivative instruments at June 30, 2008, which was recognized in accumulated other comprehensive loss within Partners capital on the Partnership s consolidated balance sheet, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings.

At March 31, 2010, the Partnership had interest rate derivative contracts having aggregate notional principal amounts of $250.0 million. Under the terms of these agreements, the Partnership will pay weighted average interest rates of 3.14%, plus the applicable margin as defined under the terms of its credit facility (see Note 11), and will receive LIBOR, plus the applicable margin, on the notional principal amounts. The interest rate swap agreements expire April 30, 2010. Beginning May 29, 2009, the Partnership discontinued hedge accounting for its interest rate derivatives which were previously qualified as hedges. As such, subsequent changes in the fair value of these derivatives will be recognized immediately within other income, net in its consolidated statements of operations. The fair value of these derivative instruments at May 29, 2009, which was recognized in accumulated other comprehensive loss within Partners capital on the Partnership s consolidated balance sheet, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged interest rates affect earnings.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. Premium costs for purchased options are recorded on the Partnership s consolidated balance sheet as the initial value of the options. Changes in the fair value of the options are recognized within other income, net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premium costs are reclassified to realized gain (loss) within other income, net at the time the option expires or is exercised. At March 31, 2010 and December 31, 2009, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $20.6 million and $43.3 million, respectively. Of the $38.5 million of net loss in accumulated other comprehensive loss within Partners Capital on the Partnership s consolidated balance sheet at March 31, 2010, the Partnership will reclassify $20.8 million of losses to the Partnership s consolidated statements of operations over the next twelve month period, consisting of $20.3 million of losses to natural gas and liquids revenue and $0.5 million of losses to interest expense. Aggregate losses of $17.7 million will be reclassified to the Partnership s consolidated statements of operations in later periods, consisting of losses to natural gas and liquids revenue. At March 31, 2010, no derivative instruments are designated as hedges for hedge accounting purposes.

The fair value of the Partnership s derivative instruments was included in its consolidated balance sheets as follows (in thousands):

	March 31, 2010	December 31, 2009
Current portion of derivative asset	$ 635	$ 998
Long-term derivative asset		361
Current portion of derivative liability	(13,311)	(33,547)
Long-term derivative liability	(7,893)	(11,126)
	$ (20,569)	$ (43,314)

The following table summarizes the Partnership s gross fair values of derivative instruments for the period indicated (in thousands):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	March 31, 2010	December 31, 2009	Balance Sheet Location	March 31, 2010	December 31, 2009
Interest rate contracts	N/A	$	$	Current portion of derivative liability	$ (485)	$ (2,247)
Interest rate contracts	N/A			Current portion of derivative asset	(118)	(593)
Commodity contracts	Current portion of derivative asset	753	1,591	N/A		
Commodity contracts	Long-term derivative asset		361	N/A		
Commodity contracts	Current portion of derivative liability	3,718	6,562	Current portion of derivative liability	(16,544)	(37,862)
Commodity contracts	Long-term derivative liability	2,385	3,435	Long-term derivative liability	(10,278)	(14,561)
		$ 6,856	$ 11,949		$ (27,425)	$ (55,263)

As of March 31, 2010, the Partnership had the following interest rate and commodity derivatives, which are not designated for hedge accounting:

Interest Fixed-Rate Swaps

Term	Amount	Type	Fair Value[(1)] Liability (in thousands)

April 2008-April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	$	(603)

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Fixed Price Swaps

Production Period	Purchased/ Sold	Commodity	Volumes[(2)]	Average Fixed Price	Fair Value[(1)] Asset/(Liability) (in thousands)
Natural Gas					
2010	Sold	Natural Gas Basis	3,390,000	(0.659)	$ (1,775)
2010	Purchased	Natural Gas Basis	5,580,000	(0.619)	2,523
2011	Sold	Natural Gas Basis	1,920,000	(0.728)	(988)
2011	Purchased	Natural Gas Basis	1,920,000	(0.758)	1,045
2012	Sold	Natural Gas Basis	720,000	(0.685)	(321)
2012	Purchased	Natural Gas Basis	720,000	(0.685)	321
Natural Gas Liquids					
2010	Sold	Propane	17,640,000	1.108	(423)
Total Fixed Price Swaps					$ 382

Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes[(2)]	Average Strike Price	Fair Value[(1)] Asset/(Liability) (in thousands)
Natural Gas						
2010	Purchased	Call	Natural Gas	6,390,000	$ 5.829	$ (672)
Natural Gas Liquids						
2010	Purchased	Put	Propane	23,688,000	$ 1.073	84
2010	Purchased	Put	Normal Butane	2,772,000	1.440	(187)
Crude Oil						
2010	Purchased	Put	Crude Oil	627,000	74.31	1,045
2010	Sold	Call	Crude Oil	1,961,250	83.83	(12,184)
2010	Purchased[(3)]	Call	Crude Oil	444,000	120.00	107
2011	Sold	Call	Crude Oil	678,000	94.68	(4,996)
2011	Purchased[(3)]	Call	Crude Oil	252,000	120.00	548
2012	Sold	Call	Crude Oil	498,000	95.83	(4,871)
2012	Purchased[(3)]	Call	Crude Oil	180,000	120.00	778
Total Options						$ (20,348)
Total Fair Value						$ (20,569)

(1) See Note 10 for discussion on fair value methodology.
(2) Volumes for Natural Gas are stated in MMBTU s. Volumes for NGLs are stated in gallons. Volumes for Crude Oil are stated in barrels.
(3)

Calls purchased for 2010 through 2012 represent offsetting positions for calls sold. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

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During the three months ended March 31, 2010 and 2009, the Partnership made net payments of $13.4 million and $5.0 million, respectively, related to the early termination of derivative contracts. Terminated derivative contracts were to expire at various times through the fourth quarter of 2012. During the three months ended March 31, 2010, and 2009, the Partnership recognized the following derivative activity related to the early termination of these derivative instruments within its consolidated statements of operations (in thousands):

Early termination of derivative contracts	For the Three Months Ended March 31, 2010	2009
Cash paid for early termination	$ (13,370)	$ (5,000)
Less: Deferred recognition of gain on early termination[1]	(5,615)	
Total realized loss at early termination[3]	(18,985)	(5,000)
Net cash derivative expense included within natural gas and liquids revenue	5,197	
Net cash derivative expense included within other income, net	(24,182)	(5,000)
Recognition of deferred hedge loss from prior periods included within natural gas and liquids revenue[2]	(15,532)	(21,944)
Recognition of deferred hedge gain from prior periods included within other income, net[2]	22,084	12,103
Total realized loss from early termination recognized in current period[3]	$ (12,433)	$ (14,841)

(1) Deferred recognition is based upon effective portion of hedges deferred to OCI.

(2) Non-Cash recognition of deferred hedge gain (loss) includes (i) theoretical premiums related to calls sold in conjunction with puts purchased in costless collars in which the puts were sold as part of the equity unwinds in 2008 and (ii) the effective portion of hedges deferred to OCI.

(3) Realized gain (loss) represents the gain/loss recognized when the derivative contract is settled. A portion of realized gain (loss) recognized in other income, net is a reclassification of unrealized gain (loss) previously recognized as a factor of recording the changes in the fair value of the derivatives prior to settlement.

In addition, the Partnership will recognize $13.7 million in the period beginning April 1, 2010 and ending on December 31, 2010 and $2.3 million and $2.0 million of income in years 2011 and 2012, respectively, the remaining period for which the hedged physical transactions are scheduled to be settled, in the Partnership s consolidated statements of operations. This $18.0 million includes $16.1 million of income related to the theoretical premiums for unwound options which had previously been purchased or sold as part of costless collars, plus $1.9 million which will be reclassified from accumulated other comprehensive loss within Partners capital on the Partnership s consolidated balance sheet.

The following tables summarize the gross effect of all derivative instruments, including the transactions referenced above, on the Partnership s consolidated statements of operations for the period indicated (in thousands):

	Gain (Loss) Recognized in Accumulated OCI Three Months ended March 31, 2010	2009	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Location	Three Months ended March 31, 2010	2009
Interest rate contracts[1]	$	$ (1,292)	Interest expense	$ (1,785)	$ (2,893)
Commodity contracts[1]			Natural gas and liquids revenue	(8,933)	(15,970)
	$	$ (1,292)		$ (10,718)	$ (18,863)

		Gain (Loss) Recognized in Income (Derivatives not designated as hedges)	
		Three Months ended March 31,	
	Location	2010	2009
Interest rate contracts(1)	Other income, net	$ (6)	$
Commodity contracts(1)	Natural gas and liquids revenue		(4,203)
Commodity contracts(2)	Other income, net	4,139	316
		$ 4,133	$ (3,887)

(1) Hedges previously designated as cash flow hedges

(2) Dedesignated cash flow hedges and non-designated hedges

NOTE 10 FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative 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 reasonable 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 assumption 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 fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 9). At March 31, 2010, all of the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and NGL options. 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 price for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula. The Partnership s interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for the Partnership s NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations, and therefore are defined as Level 3. Valuations for the Partnership s NGL options are based on forward price curves developed by the related financial institutions, and therefore are defined as Level 3.

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The following table represents the Partnership s assets and liabilities recorded at fair value as of March 31, 2010 (in thousands):

	Level 1	Level 2	Level 3	Total
Assets				
Commodity swaps	$	$ 3,889	$	$ 3,889
Commodity options		2,531	435	2,966
Total assets	$	$ 6,420	$ 435	$ 6,855
Liabilities				
Commodity swaps	$	$ (3,084)	$ (423)	$ (3,507)
Commodity options		(22,776)	(538)	(23,314)
Interest rate swaps		(603)		(603)
Total liabilities	$	$ (26,463)	$ (961)	$ (27,424)
Total derivatives	$	$ (20,043)	$ (526)	$ (20,569)

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments for the three months ended March 31, 2010 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Volume[(1)]	Amount	Volume[(1)]	Amount	Amount
Balance December 31, 2009		$	43,470	$ 1,268	$ 1,268
New contracts	17,640		8,820		
Cash settlements from unrealized loss[(2)(3)]			(25,830)	3,951	3,951
Net change in unrealized loss[(2)]		(423)		(1,371)	(1,794)
Deferred option premium recognition[(3)]				(3,951)	(3,951)
Balance March 31, 2010	17,640	$ (423)	26,460	$ (103)	$ (526)

(1) Volumes for NGLs are stated in gallons.
(2) Included within other income, 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.

Other Financial Instruments

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

The Partnership s current assets and liabilities on its consolidated balance sheets, other than the derivatives discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature. The estimated fair values of the Partnership s total debt at March 31, 2010 and December 31, 2009, which consists principally of the term loan, the Senior Notes and borrowings under the credit facility, were $1,187.1 million and $1,194.2 million, respectively, compared with the carrying amounts of $1,203.4 million and $1,254.2 million, respectively. The term loan and Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

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NOTE 11 DEBT

Total debt consists of the following (in thousands):

	March 31, 2010	December 31, 2009
Revolving credit facility	$ 280,000	$ 326,000
Term loan	425,845	433,505
8.125% Senior notes due 2015	271,762	271,628
8.75% Senior notes due 2018	223,050	223,050
Capital lease obligations	2,741	
Total debt	1,203,398	1,254,183
Less current maturities	590	
Total long term debt	$ 1,202,808	$ 1,254,183

Term Loan and Credit Facility

At March 31, 2010, the Partnership had a senior secured credit facility with a syndicate of banks which consisted of a $425.8 million term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at the Partnership s option, at either (i) adjusted LIBOR, subject to a floor of 2.0% per annum, plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding revolving credit facility borrowings at March 31, 2010 was 6.8%, and the weighted average interest rate on the outstanding term loan borrowings at March 31, 2010 was 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $9.8 million was outstanding at March 31, 2010. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet. At March 31, 2010, the Partnership had $90.2 million of remaining committed capacity under its credit facility, subject to covenant limitations.

The Partnership s senior secured credit facility restricts it from paying cash distributions unless its senior secured leverage ratio meets certain thresholds and it has minimum liquidity (both as defined in the credit agreement) of at least $50.0 million. The senior secured leverage ratio requirement was not met for the quarter ending March 31, 2010. Borrowings under the credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, except for the assets owned by Chaney Dell and Midkiff/Benedum joint ventures and Laurel Mountain; and by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is also unable to borrow under its credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement. The Partnership is in compliance with these covenants as of March 31, 2010.

The events which constitute an event of default for the 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. The credit facility requires the Partnership to maintain the following ratios:

Fiscal quarter ending:	Maximum Leverage Ratio	Maximum Senior Secured Leverage Ratio	Minimum Interest Coverage Ratio
March 31, 2010	9.25x	5.75x	1.40x
June 30, 2010	8.00x	5.00x	1.65x
September 30, 2010	7.00x	4.25x	1.90x
December 31, 2010	6.00x	3.75x	2.20x

Thereafter	5.00x	3.00x	2.75x

Fiscal quarter ending:	Maximum Leverage Ratio	Maximum Senior Secured Leverage Ratio	Minimum Interest Coverage Ratio
March 31, 2010	9.25x	5.75x	1.40x
June 30, 2010	8.00x	5.00x	1.65x
September 30, 2010	7.00x	4.25x	1.90x
December 31, 2010	6.00x	3.75x	2.20x
Thereafter	5.00x	3.00x	2.75x

As of March 31, 2010, the Partnership s leverage ratio was 5.5 to 1.0, its senior secured leverage ratio was 3.3 to 1.0, and its interest coverage ratio was 2.2 to 1.0.

Senior Notes

At March 31, 2010, the Partnership had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with a net $3.7 million of unamortized discount as of March 31, 2010. Interest on the Senior Notes in the aggregate 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, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, the Partnership may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also 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 credit facility.

Indentures governing the Senior Notes in the aggregate 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 of its assets. The Partnership is in compliance with these covenants as of March 31, 2010.

NOTE 12 COMMITMENTS AND CONTINGENCIES

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.

The Partnership s predecessor with respect to the Chaney Dell assets was named as a defendant in a set of lawsuits filed in 1999 named *Will Price, et al. v. Gas Pipelines and Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas. The lawsuits allege various claims related to industry-wide under reporting of volumes and heating value of natural gas. The plaintiffs currently seek certification of a class of royalty owners on non-federal and non-Native American lands in

Kansas, Wyoming and Colorado. The Partnership conducts limited operations in Kansas. Motions for class certification were argued in March 2005. In September 2009, the motions were denied. Plaintiffs have filed a motion for reconsideration that was argued in February 2010. The motion for reconsideration was denied in March 2010. The plaintiffs seek unspecified monetary damages (along with interest, expenses and punitive damages) and injunctive relief with regard to future gas measurement practices. At this stage, discovery has not been conducted with respect to the merits of these lawsuits and the Partnership s liability, if any, will arise under the indemnity provisions of agreements with its predecessor. Therefore, it is not currently possible to evaluate the likelihood or extent of an unfavorable outcome.

On February 26, 2010, the Partnership received notice from Williams, its partner in Laurel Mountain, alleging that certain title defects exist with respect to the real property contributed by the Partnership to Laurel Mountain. Under the Formation and Exchange Agreement with Williams: (i) Williams had nine months after closing (the Claim Date) to assert any alleged title defects, and (ii) the Partnership has 30 days following the Claim Date to contest the title defects asserted by Williams and 180 days following the Claim Date to cure those title defects. On March 26, 2010, the Partnership delivered notice, disputing Williams alleged title defects as well as the amounts claimed. The Partnership is currently conducting a review with respect to the title defects that have been alleged. At the end of the cure period with respect to any remaining title defects, the Partnership may elect, at its option, to pay Williams for the cost of such defects, up to a total of $3.5 million, or indemnify Williams with respect to such title defects. Although an adverse outcome is reasonably possible, it is not currently possible to evaluate the amount that the Partnership may be required to pay with respect to such alleged title defects.

NOTE 13 BENEFIT PLANS

Generally, all share-based payments to employees, which are not cash settled, including grants of employee stock options, are recognized in the financial statements based on their fair values on the date of the grant.

The Partnership has a Long-Term Incentive Plan (LTIP), 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 Plan is administered by a committee (the Committee) appointed by the General Partner s managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units.

Partnership Phantom Units. A phantom unit entitles a grantee to receive a common unit upon vesting of the phantom unit. Non-employee directors receive an annual grant of a maximum of 500 phantom units which, upon vesting, entitle the grantee to receive the equivalent number of common units or the cash equivalent to the then fair market value of the common limited partner units of the Partnership. In addition, the Committee may grant a participant 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, the Committee determines the vesting period for phantom units. Through March 31, 2010, phantom units granted under the LTIP generally had vesting periods of four years. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined in the LTIP. Of the units outstanding under the LTIP at March 31, 2010, 28,153 units will vest within the following twelve months. All phantom units outstanding under the LTIP at March 31, 2010 include DERs granted to the participants by the Committee. The amount paid with respect to LTIP DERs was $0.1 million for the three months ended March 31, 2009. This amount was recorded as a reduction of Partners capital on the Partnership s consolidated balance sheet. No LTIP DERs were paid for the three months ended March 31, 2010.

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Outstanding, beginning of year	52,233	126,565
Granted[1]	1,000	1,500
Matured[2]	(2,695)	(9,886)
Forfeited	(1,375)	(16,250)
Outstanding, end of year[3]	49,163	101,929
Non-cash compensation expense recognized (in thousands)	$ 122	$ (95)

(1) The weighted average prices for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense and does not represent an exercise price to be paid by the recipient, were $5.58 and $4.60 for awards granted for the three months ended March 31, 2010 and 2009, respectively.

(2) The intrinsic values for phantom unit awards exercised during the three months ended March 31, 2010 and 2009 were $0.04 million and $0.1 million, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at March 31, 2010 was $0.7 million.

At March 31, 2010, the Partnership had approximately $0.5 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIP based upon the fair value of the awards.

Partnership Unit Options. A unit option entitles a grantee to purchase the Partnership s common limited partner units 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 Partnership s common unit on the date of grant of the option. The Committee also shall determine how the exercise price may be paid by the Participant. The Committee will determine the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. Through March 31, 2010, unit options granted under the Partnership s LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. Awards will automatically vest upon a change of control of the Partnership, as defined in the Partnership s LTIP. There are 25,000 unit options outstanding under the Partnership s LTIP at March 31, 2010 that will vest within the following twelve months.

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

	Three Months Ended March 31, 2010		2009	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	100,000	$ 6.24		$
Granted			100,000	6.24
Matured				
Forfeited				
Outstanding, end of period[1][2]	100,000	$ 6.24	100,000	$ 6.24
Options exercisable, end of period[1][3]	25,000	$ 6.24		

Weighted average fair value of unit options per unit granted during the period Weighted average fair value of unit			$	100,000	$	0.14
Non-cash compensation expense recognized (in thousands)	$	1	$	2		

(1) The weighted average remaining contractual life for outstanding and exercisable options at March 31, 2010 was 8.8 years.
(2) The aggregate intrinsic value of options outstanding at March 31, 2010 was $0.8 million.
(3) There were no options exercised during the three months ended March 31, 2010 and 2009.

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At March 31, 2010, the Partnership had approximately $6,000 of unrecognized compensation expense related to unvested unit options outstanding under the Partnership s LTIP based upon the fair value of the awards.

The Partnership used the Black-Scholes option pricing model to estimate the weighted average fair value of options granted. The following weighted average assumptions were used for the period indicated:

	Three Months Ended March 31, 2009
Expected dividend yield	11.0%
Expected stock price volatility	20.0%
Risk-free interest rate	2.2%
Expected term (in years)	6.3

Employee Incentive Compensation Plan and Agreement

A wholly-owned subsidiary of the Partnership has an incentive plan (the Plan) which allows for equity-indexed cash incentive awards to employees of the Partnership (the Participants), but expressly excludes as an eligible Participant any person that, at the time of the grant, is a Named Executive Officer of the Partnership (as such term is defined under the rules of the Securities and Exchange Commission). The Plan is administered by a committee appointed by the chief executive officer of the Partnership. Under the Plan, cash bonus units may be awarded to Participants at the discretion of the committee and 325,000 bonus units were outstanding as of March 31, 2010. In addition, the subsidiary granted an award of 50,000 bonus units to an executive officer on substantially the same terms as the bonus units available under the Plan (the bonus units issued under the Plan and under the separate agreement are, for purposes hereof, referred to as Bonus Units). 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. Vesting will terminate upon termination of employment with cause. Of the 375,000 Bonus Units outstanding at March 31, 2010, 123,750 Bonus Units will vest within the following twelve months. The Partnership recognized compensation expense related to these awards based upon the fair value, which is remeasured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized $1.3 million of compensation expense within general and administrative expense on its consolidated statements of operations with respect to the vesting of these awards for the three months ended March 31, 2010. At March 31, 2010 and December 31, 2009, the Partnership has recognized $2.5 million and $1.2 million, respectively, within accrued liabilities on its consolidated balance sheet with regard to the awards, which represents their fair value.

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

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The partnership agreement provides that the General Partner will determine the costs and expenses that are 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 $0.4 million for both the three months ended March 31, 2010 and 2009 for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the three months ended March 31, 2010 and 2009. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

NOTE 15 SEGMENT INFORMATION

The Partnership has two reportable segments which reflect the way the Partnership manages its operations.

The Mid-Continent segment consists of the Chaney Dell, Elk City/Sweetwater, Velma and Midkiff/Benedum operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas.

The Appalachia segment is comprised of natural gas transportation, gathering and processing assets located in the Appalachian Basin area of the northeastern United States and services drilling activity in the Marcellus Shale area in southwestern Pennsylvania. Effective May 31, 2009, the Appalachia operations were principally conducted through its Tennessee operations and the Partnership s 49% ownership interest in Laurel Mountain, a joint venture to which the Partnership contributed its natural gas transportation, gathering and processing assets located in northeastern Appalachia. The Partnership recognizes its ownership interest in Laurel Mountain under the equity method of accounting. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates.

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

	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Three Months Ended March 31, 2010:				
Revenue:				
Revenues third party[1]	$ 24	$ 286,373	$ (4,800)	$ 281,597
Revenues affiliates	176			176
Equity income	1,462			1,462
Total revenue and other income (loss), net	$ 1,662	$ 286,373	$ (4,800)	$ 283,235
Costs and Expenses:				
Operating costs and expenses	$ 189	$ 222,197	$	$ 222,386
General and administrative[2] `			9,794	9,794
Depreciation and amortization	151	22,595		22,746
Interest expense[2]			26,431	26,431
Total costs and expenses	$ 340	$ 244,792	$ 36,225	$ 281,357
Net income (loss)	$ 1,322	$ 41,581	$ (41,025)	$ 1,878

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Three Months Ended March 31, 2009[3]:				
Revenue:				
Revenues third party[1]	$ 444	$ 183,205	$ (19,857)	$ 163,792
Revenues affiliates	10,449			10,449
Total revenue and other income (loss), net	$ 10,893	$ 183,205	$ (19,857)	$ 174,241
Costs and expenses:				
Operating costs and expenses	$ 3,520	$ 148,379	$	$ 151,899
General and administrative[2]			10,678	10,678
Depreciation and amortization	1,919	20,749		22,668
Interest expense[2]			21,108	21,108
Total costs and expenses	$ 5,439	$ 169,128	$ 31,786	$ 206,353
Net income (loss) from continuing operation	5,454	14,077	(51,643)	$ (32,112)
Income from discontinued operations			8,876	8,876
Net income (loss)	$ 5,454	$ 14,077	$ (42,767)	$ (23,236)

Capital Expenditures:	Three Months Ended March 31, 2010	2009[3]
Mid-Continent	$ 10,914	$ 66,949
Appalachia		5,246
	$ 10,914	$ 72,195

Balance Sheet	March 31, 2010	December 31, 2009
Total assets:		
Mid-Continent	$ 1,923,107	$ 1,965,219
Appalachia	141,154	170,905
Corporate other	26,296	1,839
	$ 2,090,557	$ 2,137,963

The following tables summarize the Partnership s natural gas and liquids revenues by product for the periods indicated (in thousands):

	Three Months Ended March 31, 2010	2009[3]
Natural gas and liquids:		
Natural gas	$ 90,670	$ 76,576
NGLs	160,702	66,294
Condensate	9,755	794
Other	(178)	469
Total natural gas and liquids	$ 260,949	$ 144,133

(1) Derivative contracts are held at the corporate level and are reported accordingly.
(2) The Partnership notes that 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.
(3) Restated to reflect amount reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (see Note 4) and to reflect amount reclassified from Natural Gas and Liquids to Transportation, Compression and other fees (see Note 1).

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NOTE 16 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s term loan and revolving credit facility is guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership s consolidated financial statements as of March 31, 2010 and December 31, 2009 and for the three months ended March 31, 2010 and 2009 include the financial statements of Atlas Pipeline Mid-Continent WestOk, LLC (Chaney Dell LLC) and Atlas Pipeline Mid-Continent WestTex, LLC (Midkiff/Benedum LLC), entities in which the Partnership has 95% interests and were acquired in July 2007. Under the terms of the term loan and revolving credit facility, Chaney Dell LLC and Midkiff/Benedum LLC are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership s stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership s consolidated accounts as of March 31, 2010 and December 31, 2009 and for the three months ended March 31, 2010 and 2009. 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):

			March 31, 2010		
Balance Sheet	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$	$ 159	$	$	$ 159
Accounts receivable affiliates	1,397,688			(1,397,688)	
Current portion of derivative asset		635			635
Other current assets	12	25,447	59,980		85,439
Total current assets	1,397,700	26,241	59,980	(1,397,688)	86,233
Property, plant and equipment, net		586,452	1,093,020		1,679,472
Notes receivable			1,852,928	(1,852,928)	
Equity investments	539,435	86,305		(625,740)	
Investment in joint venture		130,461			130,461
Intangible assets, net		17,996	143,706		161,702
Other assets, net	25,710	6,088	891		32,689
	$ 1,962,845	$ 853,543	$ 3,150,525	$ (3,876,356)	$ 2,090,557
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,288,079	$ 114,621	$ (1,397,688)	$ 5,012
Current portion of derivative liability		13,311			13,311
Other current liabilities	12,288	25,370	73,620		111,278
Total current liabilities	12,288	1,326,760	188,241	(1,397,688)	129,601
Long-term derivative liability		7,893			7,893
Long-term debt, less current portion	1,200,657	1,460	691		1,202,808
Other long-term liability		355			355
Partners Capital (deficit)	749,900	(482,925)	2,961,593	(2,478,668)	749,900
	$ 1,962,845	$ 853,543	$ 3,150,525	$ (3,876,356)	$ 2,090,557

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Balance Sheet	Parent	Guarantor Subsidiaries	December 31, 2009 Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 1,021	$	$	$ 1,021
Accounts receivable affiliates	1,383,871			(1,383,871)	
Current portion of derivative asset		998			998
Other current assets		42,457	73,668		116,125
Total current assets	1,383,871	44,476	73,668	(1,383,871)	118,144
Property, plant and equipment, net		588,648	1,095,736		1,684,384
Notes receivable			1,852,928	(1,852,928)	
Equity investments	568,320	237,991		(806,311)	
Investment in joint venture		132,990			132,990
Intangible assets, net		18,610	149,481		168,091
Long-term derivative asset		361			361
Other assets, net	27,332	5,525	1,136		33,993
	$ 1,979,523	$ 1,028,601	$ 3,172,949	$ (4,043,110)	$ 2,137,963
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,251,468	$ 134,446	$ (1,383,871)	$ 2,043
Current portion of derivative liability		33,547			33,547
Other current liabilities	1,813	46,250	65,076		113,139
Total current liabilities	1,813	1,331,265	199,522	(1,383,871)	148,729
Long-term derivative liability		11,126			11,126
Long-term debt, less current portion	1,254,183				1,254,183
Other long-term liability		398			398
Partners Capital (deficit)	723,527	(314,188)	2,973,427	(2,659,239)	723,527
	$ 1,979,523	$ 1,028,601	$ 3,172,949	$ (4,043,110)	$ 2,137,963

Statement of Operations	Parent	Guarantor Subsidiaries	Three Months Ended March 31, 2010 Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income, net	$	$ 89,688	$ 193,547	$	$ 283,235
Total costs and expenses	(26,659)	(91,466)	(163,232)		(281,357)
Equity income (loss)	27,319	29,766		(57,085)	
Net income (loss)	$ 660	$ 27,988	$ 30,315	$ (57,085)	$ 1,878

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Statement of Operations	Three Months Ended March 31, 2009(1) Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income (loss), net	$	$ 56,066	$ 135,356	$ (17,181)	$ 174,241
Total costs and expenses	(21,108)	(84,891)	(117,535)	17,181	(206,353)
Equity income (loss)	(2,087)	18,304		(16,217)	
Income (loss) from continuing operations	(23,195)	(10,521)	17,821	(16,217)	(32,112)
Income from discontinued operations		8,876			8,876
Net income (loss)	$ (23,195)	$ (1,645)	$ 17,821	$ (16,217)	$ (23,236)

Statement of Cash Flows	Three Months Ended March 31, 2010 Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash provided by (used in) operating activities	$ 10,987	$ 10,476	$ 67,555	$ (41,516)	$ 47,502
Net cash provided by (used in) investing activities	28,885	146,924	(6,470)	(180,572)	(11,233)
Net cash provided by (used in) financing activities	(39,872)	(158,262)	(61,085)	222,088	(37,131)
Net change in cash and cash equivalents		(862)			(862)
Cash and cash equivalents, beginning of period		1,021			1,021
Cash and cash equivalents, end of year	$	$ 159	$	$	$ 159

Statement of Cash Flows	Three Months Ended March 31, 2009(1) Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash provided by (used in) continuing operations	$ 16,336	$ 25,087	$ 26,153	$ (16,256)	$ 51,320
Net cash provided by discontinued operations		12,411			12,411
Net cash provided by (used in) operating activities	16,336	37,498	26,153	(16,256)	63,731
Net cash provided by (used in) continuing investing activities	(25,293)	(429,855)	(23,112)	405,905	(72,355)
Net cash provided by discontinued investing activities		(651)			(651)
Net cash provided by (used in) investing activities	(25,293)	(430,506)	(23,112)	405,905	(73,006)
Net cash provided by (used in) financing activities	8,957	393,400	(3,041)	(389,649)	9,667
Net change in cash and cash equivalents		392			392
Cash and cash equivalents, beginning of period	7	1,438			1,445
Cash and cash equivalents, end of year	$ 7	$ 1,830	$	$	$ 1,837

(1) Restated to reflect amounts reclassified to discontinued operations due to the Partnership s sale of its NOARK gas gathering and interstate pipeline system (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, 2009. 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.

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 services in the Anadarko and Permian Basins located in the southwestern and mid-continent United States and the Appalachian Basin in the northeastern United States. In addition, we are a leading provider of natural gas processing and treating services in Oklahoma and Texas.

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Mid-Continent and Appalachia.

In our Mid-Continent operations, we own, have interests in and operate eight natural gas processing plants with aggregate capacity of approximately 900 MMCFD and one treating facility with a capacity of approximately 200 MMCFD. These facilities are connected to approximately 9,100 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas, which gathers gas from wells and central delivery points to our natural gas processing and treating plants, as well as third-party pipelines.

Our Appalachia operations are conducted principally through our 49% ownership interest in the Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), which owns and operates approximately 1,800 miles of natural gas gathering systems in the Appalachian Basin located in the northeastern United States. We also own and operate approximately 80 miles of active natural gas gathering pipelines in northeastern Tennessee.

Recent Events

On January 7, 2010, we executed amendments to warrants previously issued, along with our common units, in connection with a private placement to institutional investors that closed on August 20, 2009. The common units and warrants were issued and sold in a transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and credit facility (see -Term Loan and Credit Facility) and to fund the early termination of certain derivative agreements (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 9).

On March 31, 2010, we and the Operating Partnership amended our respective partnership agreements to temporarily waive the requirement that the General Partner make aggregate cash contributions of approximately $0.3 million, which was required in connection with our issuance of an aggregate of 2,689,765 of our common units upon the exercise of certain warrants in January 2010. The waiver will remain in effect until the General Partner has received aggregate distributions from us sufficient to fund the required capital contribution. During the waiver period, the aggregate ownership percentage attributable to the General Partner s general partner interest in us is reduced to 1.9%. Both amendments were approved by our conflicts committee and managing board, and are effective as of January 11, 2010.

Contractual Revenue Arrangements

Our principal revenue is generated from the gathering and sale of natural gas and natural gas liquids (NGLs). Variables that affect our revenue are:

- the volume of natural gas we gather and process which, in turn, depends upon the number of wells connected to our gathering systems, the amount of natural gas they produce, and the demand for natural gas and NGLs;
- the price of the natural gas we gather and process and the NGLs 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 British Thermal Unit (BTU) content of the gas that is gathered and processed;
- the contract terms with each producer; and
- the efficiency of our gathering systems and processing plants.

Revenue consists of 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 of 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. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas.

In our Appalachia segment, substantially all of the natural gas we gather via Laurel Mountain is for Atlas Energy under contracts in which Laurel Mountain earns a fee equal to a percentage, generally 16%, of the gross sales price for natural gas, inclusive of the effects of financial and physical hedging, subject, in most cases, to a minimum of $0.35 per thousand cubic feet, or MCF, depending on the ownership of the well. The balance of the natural gas gathered by Laurel Mountain and our Tennessee operations is for third-party operators generally under fixed-fee contracts. See Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 2 -Revenue Recognition for further discussion of contractual revenue arrangements.

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Recent Trends and Uncertainties

The midstream natural gas industry links the exploration and production of natural gas and the delivery of its components to end-use markets and provides natural gas gathering, compression, dehydration, treating, conditioning, processing, fractionation and transportation services. This industry group is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

We face competition in obtaining natural gas supplies for our processing and related services operations. Competition for natural gas supplies is based primarily on the location of gas-gathering facilities and gas-processing plants, operating efficiency and reliability, and the ability to obtain a satisfactory price for products recovered. Competition for customers is based primarily on price, delivery capabilities, quality of assets, flexibility, service history and maintenance of high-quality customer relationships. Many of our competitors operate as master limited partnerships and enjoy a cost of capital comparable to and, in some cases lower than, ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas. We believe the primary difference between us and some of our competitors is that we provide an integrated and responsive package of midstream services, while some of our competitors provide only certain services. We believe that offering an integrated package of services, while remaining flexible in the types of contractual arrangements that we offer producers, allows us to compete more effectively for new natural gas supplies in our regions of operations.

As a result of our Percent of Proceeds and Keep-Whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas and NGLs. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. However, energy market uncertainty has negatively impacted North American drilling activity in the recent past. Lower drilling levels and shut-in wells over a sustained period would have a negative effect on natural gas volumes gathered and processed.

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. We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. See Item 3. Quantitative and Qualitative Disclosures About Market Risk -Commodity Price Risk for further discussion of commodity price risk.

Currently, there is an extremely significant level of uncertainty in the financial markets. This uncertainty presents additional potential risks to us. These risks include the availability and costs associated with our borrowing capabilities and raising additional capital, and an increase in the volatility of the price of our common units. While we have no definitive plans to access the capital markets, should we decide to do so in the near future, the terms, size, and cost of new debt or equity could be less favorable than in previous transactions.

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Results of Operations

The following table illustrates selected volumetric information related to our reportable segments for the periods indicated:

	Three Months Ended March 31,	
	2010	2009
Operating data[1]:		
Appalachia:		
Average throughput volumes (mcfd)	105,557	98,529
Mid-Continent:		
Velma system:		
Gathered gas volume (mcfd)	73,220	65,955
Processed gas volume (mcfd)	70,742	63,875
Residue gas volume (mcfd)	55,482	50,173
NGL volume (bpd)	7,760	7,035
Condensate volume (bpd)	477	345
Elk City/Sweetwater system:		
Gathered gas volume (mcfd)	228,164	253,878
Processed gas volume (mcfd)	171,797	253,918
Residue gas volume (mcfd)	154,648	232,038
NGL volume (bpd)	9,397	11,719
Condensate volume (bpd)	480	529
Chaney Dell system:		
Gathered gas volume (mcfd)	222,004	303,022
Processed gas volume (mcfd)	206,912	227,855
Residue gas volume (mcfd)	188,232	255,976
NGL volume (bpd)	12,580	13,685
Condensate volume (bpd)	759	927
Midkiff/Benedum system:		
Gathered gas volume (mcfd)	157,693	153,978
Processed gas volume (mcfd)	149,084	146,055
Residue gas volume (mcfd)	99,640	105,238
NGL volume (bpd)	24,387	22,650
Condensate volume (bpd)	690	789

(1) Mcf represents thousand cubic feet; Mcfd represents thousand cubic feet per day; Bpd represents barrels per day.

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009

Revenue. The following table details the revenue changes between the three months ended March 31, 2010 and 2009 (in thousands):

	Three Months Ended March 31,			
	2010	2009[1]	Change	Percent Change
Revenues:				
Natural gas and liquids	$ 260,949	$ 144,133	$ 116,816	81.0%
Transportation, compression, processing and other fee revenue	14,255	24,959	(10,704)	(42.9)%
Equity income in joint venture	1,462		1,462	N/A
Other income, net	6,569	5,149	1,420	27.6%

Total Revenues	$ 283,235	$ 174,241	$ 108,994	62.6%

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the NOARK gas gathering and interstate pipeline system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 4).

Natural gas and liquids revenue was $260.9 million for the three months ended March 31, 2010, an increase of $116.8 million from $144.1 million for the prior year comparable period. The increase was

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primarily attributable to a favorable price change as a result of higher realized commodity prices combined with lower qualified hedge losses, partially offset by lower production volumes at Elk City and Chaney Dell. 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.

Processed natural gas volume on the Chaney Dell system was 206.9 MMCFD for the three months ended March 31, 2010, a decrease of 9.2% compared to 227.9 MMCFD for the prior year. The Chaney Dell system decreased its NGL production volume to 12,580 BPD for the three months ended March 31, 2010, an 8.1% decrease when compared to the prior year period of 13,685 BPD. Processed natural gas volume on the Elk City/Sweetwater system averaged 171.8 MMCFD for the three months ended March 31, 2010, a decrease of 32.3% from the prior year period. NGL production volume for the Elk City/Sweetwater system was 9,397 BPD, a decrease of 19.8% from the prior year period. Decreased volumes for both systems were a result of weather related downtime at the facilities and a decreased number of well connects over the past year, resulting from lower capital spending. The Midkiff/Benedum system increased its NGL production volume for the three months ended March 31, 2010 by 7.7% when compared to the prior year period to 24,387 BPD, representing an increase in production efficiency, primarily due to the start-up of the new Consolidator plant. Processed natural gas volume averaged 70.7 MMCFD on the Velma system for the three months ended March 31, 2010, an increase of 10.8% from the prior year period, mainly due to the new gathering line from the Madill area.

Transportation, compression, processing and other fee revenue decreased to $14.3 million for the three months ended March 31, 2010 compared with $25.0 million for the prior year period. This $10.7 million decrease was primarily due to a $10.1 million decrease from the Appalachia system as a result of our May 2009 contribution of the majority of the system to Laurel Mountain, a joint venture in which we have a 49% ownership interest. After the contribution, we recognized our ownership interest in the net income of Laurel Mountain as equity income on our consolidated statements of operations.

Equity income of $1.5 million for the three months ended March 31, 2010 represents our ownership interest in the net income of Laurel Mountain.

Other income, net, including the impact of certain gains and losses recognized on derivatives, was a gain of $6.6 million for the three months ended March 31, 2010, which represents a favorable movement of $1.4 million from the prior year period gain of $5.2 million. We enter into derivative instruments principally 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.

Costs and Expenses. The following table details the costs and expenses changes between the three months ended March 31, 2010 and 2009 (in thousands):

	Three Months Ended March 31,			
	2010	2009(1)	Change	Percent Change
Costs and Expenses:				
Natural gas and liquids	$ 206,663	$ 134,745	$ 71,918	53.4%
Plant operating	15,534	13,823	1,711	12.4%
Transportation and compression	189	3,331	(3,142)	(94.3)%
General and administrative	9,794	10,678	(884)	(8.3)%
Depreciation and amortization	22,746	22,668	78	0.3%
Interest expense	26,431	21,108	5,323	25.2%
Total Costs and Expenses	$ 281,357	$ 206,353	$ 75,004	36.3%

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the NOARK gas gathering and interstate pipeline system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 4).

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Natural gas and liquids cost of goods sold of $206.7 million for the three months ended March 31, 2010 represented an increase of $71.9 million from the prior year period due primarily to an increase in average commodity prices partially offset by lower volumes in comparison to the prior year period, as discussed above in revenues. Plant operating expenses of $15.5 million for the three months ended March 31, 2010 represented an increase of $1.7 million from the prior year period due primarily to a $1.4 million increase associated with the Midkiff/Benedum system resulting from higher compressor rentals and labor costs related to the new Consolidator gas plant. Transportation and compression expenses decreased to $0.2 million for the three months ended March 31, 2010 compared with $3.3 million for the prior year period due to our contribution of the Appalachia system to Laurel Mountain.

General and administrative expense, including amounts reimbursed to affiliates, decreased $0.9 million to $9.8 million for the three months ended March 31, 2010 compared with $10.7 million for the prior year period. The decrease was primarily related to a $0.6 million decrease in salaries and wages resulting mainly from non-recurring severance expense incurred during the prior year period.

Depreciation and amortization increased $0.1 million to $22.7 million for the three months ended March 31, 2010. Depreciation in the Mid-Continent segment increased $1.8 million due primarily to expansion capital expenditures incurred subsequent to March 31, 2009, offset by a decrease of $1.7 million in the Appalachia segment due to the sale of assets in the second quarter of 2009.

Interest expense increased to $26.4 million for the three months ended March 31, 2010 as compared with $21.1 million for the prior year period. This $5.3 million increase was primarily due to a $2.9 million increase in interest expense associated with outstanding borrowings on our revolving credit facility, a $1.5 million increase in interest expense associated with our term loan and $1.2 million of lower interest capitalized as a component of capital expenditures. The higher interest expense on our credit facility and term loan is due to higher weighted average interest rates of 6.8% in the three months ended March 31, 2010 compared to average rates of 3.1% in the prior year period. The lower capitalized interest is a result of fewer capital projects in the current period.

Other income items. The following table details the changes between the three months ended March 31, 2010 and 2009 for discontinued operations and (gain) loss attributable to non-controlling interests (in thousands):

	Three Months Ended March 31,			
	2010	**2009(1)**	**Change**	**Percent Change**
Income from discontinued operations	$	$ 8,876	$ (8,876)	(100.0)%
Income attributable to non-controlling interests	(1,317)	(469)	(848)	(180.8)%

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the NOARK gas gathering and interstate pipeline system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 4).

Income from discontinued operations, which consists of amounts associated with the NOARK gas gathering and interstate pipeline system, decreased $8.9 million from the prior year period due to its sale in May 2009.

Income attributable to non-controlling interests was $1.3 million for the three months ended March 31, 2010 compared with income attributable to non-controlling interests of $0.5 million for the prior year period. This change was primarily due to higher net income for the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to accomplish our acquisition of control of the respective systems. The increase in net income of the Chaney Dell and Midkiff/Benedum joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher prices. The non-controlling interest expense represents Anadarko Petroleum Corporation s 5% interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash generated from operations and borrowings under our 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 borrowings; and
- debt principal payments through operating cash flows and additional borrowings as they become due or by the issuance of additional limited partner units or asset sales.

At March 31, 2010, we had $280.0 million of outstanding borrowings under our $380.0 million senior secured credit facility and $9.8 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $90.2 million of remaining committed capacity under the credit facility, subject to covenant limitations (see -Term Loan and Revolving Credit Facility). We were in compliance with the credit facility s covenants at March 31, 2010. At March 31, 2010, we had a working capital deficit of $43.4 million compared with a $30.6 million working capital deficit at December 31, 2009. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash flow. We may 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.

Recent instability in the financial markets, as a result of recession or otherwise, has increased the cost of capital while the availability of funds from those markets has diminished. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to the extent required and on acceptable terms.

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Cash Flows Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009

The following table details the cash flow changes between the three months ended March 31, 2010 and 2009 (in thousands):

	Three Months Ended March 31,			
	2010	**2009**	**Change**	**Percent Change**
Net cash provided by operating activities	$ 47,502	$ 63,731	$ (16,229)	(25.5)%
Net cash used in investing activities	(11,233)	(73,006)	61,773	84.6%
Net cash provided by (used in) financing activities	(37,131)	9,667	(46,798)	(484.1)%
Net change in cash and cash equivalents	$ (862)	$ 392	$ (1,254)	(319.9)%

Net cash provided by operating activities of $47.5 million for the three months ended March 31, 2010 represented a decrease of $16.2 million from $63.7 million of net cash provided by operating activities for the prior year period. The decrease was derived from a $41.2 million decrease in working capital and a $12.4 million decrease in cash provided by discontinued operations, partially offset by a $37.4 million favorable movement in net earnings from continuing operations, excluding non-cash charges. The decrease in working capital was primarily due to unfavorable derivative cash settlements of $49.1 million as a result of a $19.5 million favorable monetization of derivatives in the prior period combined with an $8.4 million unfavorable change related to the early termination of a portion of derivative contracts. The additional $21.2 million unfavorable derivatives cash settlement is primarily due to higher commodity prices in the current period (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 9). The $37.4 million favorable movement in net earnings from continuing operations, excluding non-cash charges was primarily due to a $33.7 million favorable gross margin related to the sale of natural gas and liquids, as a result of higher prices.

Net cash used in investing activities was $11.2 million for the three months ended March 31, 2010, a decrease of $61.8 million from $73.0 million of net cash used in investing activities for the prior year period. This decrease was principally due to a $61.3 million decrease in capital expenditures (see further discussion of capital expenditures under Liquidity and Capital Resources -Capital Requirements).

Net cash used in financing activities was $37.1 million for the three months ended March 31, 2010, a decrease of $46.8 million from $9.7 million of net cash provided by financing activities for the prior year period. This decrease was principally due to a $75.7 million net increase in repayments under our credit facilities, partially offset by an $18.2 million decrease in distributions paid and a $10.4 million net increase of net proceeds from sale of equity.

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 March 31,	
	2010	2009(1)
Maintenance capital expenditures	$ 1,171	$ 544
Expansion capital expenditures	9,743	71,651
Total	$ 10,914	$ 72,195

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the NOARK gas gathering and interstate pipeline system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 4).

Expansion capital expenditures decreased to $9.7 million for the three months ended March 31, 2010 compared with $71.7 million for the prior year period due partially to the construction of our Madill to Velma pipeline, our Nine Mile gas plant and compressor upgrades in the prior period, compounded by a reduction of well connects in the current period. The increase in maintenance capital expenditures for the three months ended March 31, 2010 when compared with the comparable prior year period was due to fluctuations in the timing of scheduled maintenance activity. As of March 31, 2010, we have approved expenditures of approximately $47.1 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Partnership Distributions

Subject to the restrictions noted below, 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 of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

Our General Partner is granted discretion by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds 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 98.1% to our common limited partners and 1.9% 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 1.9% of the aggregate amount of cash being distributed. During July 2007, our General Partner, holder of all of our incentive distribution rights, 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. No incentive distributions were declared for the three months ended March 31, 2010.

Our senior secured credit facility restricted us from paying cash distributions through the end of 2009. Commencing with the quarter ending March 31, 2010, cash distributions can be paid, only if our senior secured leverage ratio meets certain thresholds and we have minimum liquidity (both as defined in the credit agreement) of at least $50.0 million at the end of the quarter (see -Term Loan and Revolving Credit Facility).

Off Balance Sheet Arrangements

As of March 31, 2010, our off balance sheet arrangements are limited to our letters of credit, issued under the provisions of our revolving credit facility, totaling $9.8 million. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety and (iii) counterparty support.

Common Equity Offerings

In August 2009, we sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. We also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2.0% general partner interest in us. In addition, we issued warrants granting investors in our private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and revolving credit facility (see -Term Loan and Revolving Credit Facility) and to fund the early termination of certain derivative agreements (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 9).

On January 7, 2010, we executed amendments to the warrants which were originally issued in August 2009. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and credit facility (see -Term Loan and Credit Facility) and to fund the early termination of certain derivative agreements (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 9).

The common units and warrants sold by us in the August 2009 private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement required us to (a) file a registration statement with the Securities and Exchange Commission for the privately placed common units and those underlying the warrants by September 21, 2009 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by November 18, 2009. We filed a registration statement with the Securities and Exchange Commission in satisfaction of the registration requirements of the registration rights agreement on September 3, 2009, and the registration statement was declared effective on October 14, 2009.

Term Loan and Credit Facility

At March 31, 2010, we had a senior secured credit facility with a syndicate of banks which consisted of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at our option, at either (i) adjusted LIBOR, subject to a floor of 2% per annum, plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rates on the outstanding revolving credit facility and term loan borrowings at March 31, 2010 were 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $9.8 million was outstanding at March 31, 2010. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet.

Our senior secured credit facility restricts us from paying cash distributions unless our senior secured leverage ratio meets certain thresholds and we have minimum liquidity (both as defined in the credit agreement) of at least $50.0 million. The senior secured leverage ratio requirement for paying cash distributions was not met

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for the quarter ending March 31, 2010. Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum joint ventures and the Laurel Mountain joint venture. Borrowings are also secured by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including 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 credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement. We are in compliance with these covenants as of March 31, 2010.

The events which constitute an event of default for our 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. The credit facility requires us to maintain the following ratios:

Fiscal quarter ending:	**Maximum Leverage Ratio**	**Maximum Senior Secured Leverage Ratio**	**Minimum Interest Coverage Ratio**
March 31, 2010	9.25x	5.75x	1.40x
June 30, 2010	8.00x	5.00x	1.65x
September 30, 2010	7.00x	4.25x	1.90x
December 31, 2010	6.00x	3.75x	2.20x
Thereafter	5.00x	3.00x	2.75x

As of March 31, 2010, our leverage ratio was 5.5 to 1.0, our senior secured leverage ratio was 3.3 to 1.0, and our interest coverage ratio was 2.2 to 1.0.

Senior Notes

At March 31, 2010, we had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with a net $3.7 million of unamortized discount as of March 31, 2010. Interest on the Senior Notes in the aggregate 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, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, we may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also 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 credit facility.

Indentures governing the Senior Notes in the aggregate 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 of our assets. We are in compliance with these covenants as of March 31, 2010.

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Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within our Annual Report on Form 10-K for the year ended December 31, 2009, and there have been no material changes to these policies through March 31, 2010.

Fair Value of Financial Instruments

We use 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 our own market assumptions, which are used if observable inputs are not reasonable available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

The hierarchy defines three levels of inputs that may be used to measure fair value:

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

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

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

We use a fair value methodology to value the assets and liabilities for our outstanding derivative contracts (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 9). At March 31, 2010, all of our derivative contracts are defined as Level 2, with the exception of our NGL fixed price swaps and NGL options. Our Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. Our interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for our NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations and therefore are defined as Level 3. Valuations for our NGL options are based on forward price curves developed by the related financial institutions, and therefore are defined as Level 3.

Recently Adopted Accounting Standards

In January 2010, the FASB issued Accounting Standards Update 2010-06, Fair Value Measurements and Disclosures - Improving Disclosures about Fair Value Measurements, to provide enhanced disclosure requirements for activity in Levels 1, 2 and 3 fair value measurements. The update requires significant transfers in and out of Levels 1 and 2 fair value measurements to be reported separately and the reasons for such transfers to be disclosed. The update also requires information regarding purchases, sales, issuances, and settlements to be disclosed separately on a gross basis in the reconciliation of fair value measurements using unobservable inputs for all activity in Level 3 fair value measurements. Additionally, the update clarifies that fair value measurement for each class of assets and liabilities must be disclosed as well as disclosures pertaining to the inputs and valuation techniques for both recurring and nonrecurring fair value measurements in Levels 2 and 3. These requirements are effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those requirements will be effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. We adopted these requirements on January 1, 2010 and it did not have a material impact on our financial position, results of operations or related disclosures.

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 of our market risk sensitive instruments were entered into for purposes other than trading.

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodical use of derivative instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on March 31, 2010. 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 and interest-rate derivative contracts are banking institutions currently participating in our revolving credit facility. We may choose to do business with counterparties outside of our credit facility in the future. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At March 31, 2010, we had a $380.0 million senior secured revolving credit facility ($280.0 million outstanding). We also had $425.8 million outstanding under our senior secured term loan at March 31, 2010. Borrowings under the credit facility bear interest, at our option at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus

0.5% or the Wachovia Bank prime rate (each plus the applicable margin). On May 29, 2009, we entered into an amendment to our senior secured revolving credit facility agreement which, among other changes, set a floor for the LIBOR interest rate of 2.0% per annum. The weighted average interest rate for the revolving credit facility borrowings was 6.8% at March 31, 2010, and the weighted average interest rate for the term loan borrowings was 6.8% at March 31, 2010.

At March 31, 2010, we have interest rate derivative contracts having aggregate notional principal amounts of $250.0 million. Under the terms of these agreements, we will pay weighted average interest rates of 3.14%, plus the applicable margin as defined under the terms of our revolving credit facility, and will receive LIBOR, plus the applicable margin, on the notional principal amounts. The interest rate swap agreements expire April 30, 2010. Beginning May 29, 2009, we discontinued hedge accounting for our interest rate derivatives which were previously qualified as hedges. As such, subsequent changes in fair value of these derivatives will be recognized immediately within other income, net in our consolidated statements of operations.

Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by $0.2 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. Average estimated unhedged 2010 market prices for NGLs, natural gas and condensate, based upon New York Mercantile Exchange (NYMEX) forward price curves as of April 5, 2010, are $0.97 per gallon, $4.87 per million BTU and $87.96 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended March 31, 2011 by approximately $20.0 million.

We use a number of different derivative instruments, principally swaps and options, 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 or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. See Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 9 for further discussion of our derivative instruments.

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 our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

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Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that as of March 31, 2010, 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.

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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, 2009.

ITEM 6. EXHIBITS

Exhibit No.	Description
3.1	Certificate of Limited Partnership[1]
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[9]
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership[11]
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership[21]
3.3	Amended and Restated Certificate of Designation for 12% Cumulative Class B Preferred Units[11]
4.1	Common unit certificate[1]
4.2	8 $^{1}/8$% Senior Notes Indenture dated December 20, 2005[10]
4.3	8 $^{3}/4$% Senior Notes Indenture dated June 27, 2008[7]
10.1(a)	Revolving Credit and Term Loan Agreement dated July 27, 2007 by and among Atlas Pipeline Partners, L.P., Wachovia Bank, National Association and the several guarantors and lenders hereto[4]
10.1(b)	Amendment No. 1 and Agreement to the Revolving Credit and Term Loan Agreement, dated June 12, 2008[6]
10.1(c)	Increase Joinder dated June 27, 2008[8]
10.1(d)	Amendment No. 2 to Revolving Credit and Term Loan Agreement, dated May 29, 2009[12]
10.2	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[21]
10.3	Form of Warrant to purchase common units dated August 20, 2009[13]
10.4	Form of First Amendment to Warrant to purchase common units dated January 7, 2010[19]
10.5	Long-Term Incentive Plan[20]
10.6	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan[20]
10.7	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement[20]
10.8	Formation and Exchange Agreement dated March 31, 2009 between Williams Field Services Group, LLC, Williams Laurel Mountain, LLC, Atlas Pipeline Partners, L.P., Atlas Pipeline Operating Partnership, L.P. and APL Laurel Mountain, LLC[14]
10.9	Employment Agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay[14]
10.10	

Securities Purchase Agreement dated April 7, 2009, by and between Atlas Pipeline Mid-Continent, LLC and Spectra Energy Partners OLP, LP[15]

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10.11	Atlas Pipeline Holdings II, LLC Limited Liability Company Agreement(16)
10.12	ATN Option Agreement dated as of June 1, 2009, by and among APL Laurel Mountain, LLC, Atlas Pipeline Operating Partnership, L.P. and Atlas Energy Resources, LLC(17)
10.13	Amended and Restated Limited Liability Company Agreement of Laurel Mountain Midstream, LLC dated as of June 1, 2009(17)
10.14	Letter Agreement, dated as of August 31, 2009, between Atlas America, Inc. and Eric Kalamaras(18)
10.15	Phantom Unit Grant Agreement between Atlas Pipeline Mid-Continent, LLC and Eric Kalamaras, dated September 14, 2009(18)
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

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(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 July 3, 2008.
(9) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
(10) Previously filed as an exhibit to current report on Form 8-K on December 21, 2005.
(11) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
(12) Previously filed as an exhibit to current report on Form 8-K on June 1, 2009.
(13) Previously filed as an exhibit to current report on Form 8-K on August 20, 2009.
(14) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2009.
(15) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2009.
(16) Previously filed as an exhibit to current report on Form 8-K on June 2, 2009.
(17) Previously filed as an exhibit to current report on Form 8-K on June 5, 2009.
(18) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2009.
(19) Previously filed as an exhibit to current report on Form 8-K on January 8, 2010.
(20) Previously filed as an exhibit to annual report on Form 10-K for the year ended December 31, 2009.
(21) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.

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SIGNATURES

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

ATLAS PIPELINE PARTNERS, L.P.

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

Date: May 7, 2010	By: /s/ EUGENE N. DUBAY Chief Executive Officer, President and Managing Board Member of the General Partner
Date: May 7, 2010	By: /s/ ERIC T. KALAMARAS Eric T. Kalamaras Chief Financial Officer of the General Partner
Date: May 7, 2010	By: /s/ ROBERT W. KARLOVICH, III Robert W. Karlovich, III Chief Accounting Officer of the General Partner

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