ATLAS PIPELINE PARTNERS LP
Form 10-Q
May 11, 2009
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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, 2009

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

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

The number of common units of the registrant outstanding on May 5, 2009 was 47,659,119.

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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, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,912	$ 1,520
Accounts receivable affiliates		537
Accounts receivable	81,302	112,365
Current portion of derivative asset		44,961
Prepaid expenses and other	10,893	11,997
Total current assets	94,107	171,380
Property, plant and equipment, net	2,073,517	2,022,937
Intangible assets, net	187,258	193,647
Other assets, net	27,349	25,232
	$ 2,382,231	$ 2,413,196
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable affiliates	$ 12,400	$
Accounts payable	51,626	70,691
Accrued liabilities	39,881	21,701
Current portion of derivative liability	66,698	60,396
Preferred unit redemption obligation	15,000	
Accrued producer liabilities	39,618	67,406
Total current liabilities	225,223	220,194
Long-term derivative liability	23,210	48,159
Long-term debt, less current portion	1,525,403	1,493,427
Other long-term liability	533	574
Commitments and contingencies		
Partners capital:		
Class A preferred limited partner s interest	2,978	27,853
Class B preferred limited partner s interest	15,411	10,007
Common limited partners interests	694,028	735,742
General partner s interest	13,976	14,521
Accumulated other comprehensive loss	(87,373)	(104,944)
	639,020	683,179
Non-controlling interest	(31,158)	(32,337)

Total partners capital	607,862	650,842
	$ 2,382,231	$ 2,413,196

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, 2009	Three Months Ended March 31, 2008
Revenue:		
Natural gas and liquids	$ 158,618	$ 366,119
Transportation, compression and other fees affiliates	10,068	9,159
Transportation, compression and other fees third parties	16,412	14,862
Other income (loss), net	5,148	(86,754)
Total revenue and other income (loss), net	190,246	303,386
Costs and expenses:		
Natural gas and liquids	138,059	276,664
Plant operating	13,823	14,935
Transportation and compression	4,767	3,812
General and administrative	10,644	4,370
Compensation reimbursement affiliates	375	1,129
Depreciation and amortization	24,680	21,844
Interest	21,134	20,381
Asset impairment		3,981
Total costs and expenses	213,482	347,116
Net loss	(23,236)	(43,730)
Loss attributable to non-controlling interests	(469)	(2,090)
Preferred unit dividends	(900)	(137)
Preferred unit imputed dividend cost		(505)
Net loss attributable to common limited partners and the general partner	$ (24,605)	$ (46,462)
Allocation of net loss attributable to common limited partners and the general partner:		
Common limited partners interest	$ (24,110)	$ (52,387)
General partner s interest	(495)	5,925
Net loss attributable to common limited partners and the general partner	$ (24,605)	$ (46,462)
Net loss attributable to common limited partners per unit:		
Basic	$ (0.52)	$ (1.35)
Diluted	$ (0.52)	$ (1.35)
Weighted average common limited partner units outstanding:		
Basic	45,971	38,763
Diluted	45,971	38,763

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, 2009

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units Class A Preferred	Class B Preferred	Common	Class A Preferred Limited Partner	Class B Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interest	Total Partners Capital
Balance at January 1, 2009	30,000	10,000	45,954,808	$ 27,853	$ 10,007	$ 735,742	$ 14,521	$ (104,944)	$ (32,337)	$ 650,842
Issuance of common units										
Redemption of Class A cumulative convertible preferred limited partner units	(10,000)			(10,000)						(10,000)
Issuance of Class B preferred limited partner units		5,000			4,961					4,961
Reclassification of Class A preferred unit equity to preferred unit obligations				(15,000)						(15,000)
General partner capital contribution							308			308
Distributions to non-controlling interests									710	710
Unissued common units under incentive plans						(93)				(93)
Issuance of units under incentive plans			219,058							
Distributions paid to common limited partners, the general partner and preferred limited partners				(325)	(7)	(17,463)	(358)			(18,153)
Distribution equivalent rights paid on unissued units under incentive plans						(48)				(48)
Other comprehensive								17,571		17,571

income										
Net loss				450	450	(24,110)	(495)		469	(23,236)
Balance at March 31, 2009	20,000	15,000	46,173,866	$ 2,978	$ 15,411	$ 694,028	$ 13,976	$ (87,373)	$ (31,158)	$ 607,862

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, 2009	Three Months Ended March 31, 2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (23,236)	$ (43,730)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	24,680	21,844
Asset impairment		3,981
Non-cash loss on derivative value, net	43,885	74,814
Non-cash compensation income	(93)	(2,795)
Gain on asset sales and dispositions		(132)
Amortization of deferred finance costs	1,017	679
Net distributions to non-controlling interest holders	710	(413)
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable and prepaid expenses and other	32,167	(17,447)
Accounts payable and accrued liabilities	(27,626)	22,066
Accounts payable and accounts receivable affiliates	12,937	(3,989)
Net cash provided by operating activities	64,441	54,878
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net cash received in connection with acquisitions		1,281
Capital expenditures	(72,913)	(84,069)
Other	(93)	(251)
Net cash used in investing activities	(73,006)	(83,039)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	158,000	75,000
Repayments under credit facility	(136,000)	(15,000)
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)	(41,143)
Other	(159)	(121)
Net cash provided by financing activities	8,957	18,736
Net change in cash and cash equivalents	392	(9,425)
Cash and cash equivalents, beginning of period	1,520	11,980
Cash and cash equivalents, end of period	$ 1,912	$ 2,555

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

MARCH 31, 2009

(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 transmission, 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 2% 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% 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 (see Note 4) and 15,000 $1,000 par value Class B preferred limited partner units (see Note 5). At March 31, 2009, the Partnership had 46,173,866 common limited partnership units, including the 5,754,253 common units held by the General Partner; 20,000, $1,000 par value cumulative convertible Class A preferred limited partnership units outstanding, and 15,000 $1,000 par value Class B preferred units held by the General Partner (see Note 4 and 5).

The Partnership s General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas America, Inc. and its affiliates (Atlas America), a publicly-traded company (NASDAQ: ATLS) which owns a 64.4% ownership interest in AHD at March 31, 2009, also owns 1,112,000 of the Partnership s common limited partnership units, representing a 2.3% ownership interest in the Partnership, and a 48.3% ownership interest in Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a publicly-traded company (NYSE: ATN). Substantially all of the natural gas the Partnership transports in the Appalachian basin is derived from wells operated by Atlas Energy.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2008 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, 2008. The results of operations for the three month period ended March 31, 2009 may not necessarily be indicative of the results of operations for the full year ending December 31, 2009. 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, 2008.

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 2% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

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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. The Partnership has an agreement with Pioneer whereby Pioneer has an option to buy up to an additional 22.0% interest in the Midkiff/Benedum system beginning on June 15, 2009 and ending on November 1, 2009. If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22.0% interest if fully exercised. The Partnership will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options.

Use of Estimates

The preparation of the Partnership s consolidated financial statements in conformity with accounting principles generally accepted in the United States 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 for the three months ended March 31, 2009 represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

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 (loss) attributable to participating securities and 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 2% interest and incentive distributions (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 Emerging Issue Task Force s (EITF) Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF No. 07-4), an update of EITF No. 03-6, Participating Securities and the Two-Class Method Under FASB Statement No. 128 (EITF No. 03-6). EITF 07-4 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. EITF 07-4 also 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 guidance of EITF 07-4, 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.

On January 1, 2009, the Partnership adopted Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 applies to the calculation of earnings per share (EPS) described in paragraphs 60 and 61 of Financial Accounting Standards Board (FASB) Statement No. 128, Earnings per Share for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS 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. As such, FSP EITF 03-6-1 provides that the net income (loss) utilized in the calculation of net income (loss) per unit must be after the allocation of income (loss) to the phantom units on a pro-rata basis. FSP EITF 03-6-1 requires entities to retroactively adjust all prior period earnings per unit computations per its guidance.

The following is a reconciliation of net income (loss) allocated to the general partner and common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands, except per unit data):

	Three Months Ended March 31,	
	2009	2008
Net loss	$ (23,236)	$ (43,730)
Loss attributable to non-controlling interest	(469)	(2,090)
Preferred unit dividends	(900)	(137)
Preferred unit imputed dividend cost		(505)
Net loss attributable to common limited partners and the general partner	(24,605)	(46,462)
General partner s actual cash incentive distributions declared		7,000
General partner s actual 2% ownership interest	(495)	(1,075)
Net income (loss) attributable to the general partner s ownership interests	(495)	5,925
Net loss attributable to common limited partners	(24,110)	(52,387)
Less: net loss attributable to participating securities phantom units[1]	(62)	(193)
Net loss utilized in the calculation of net loss attributable to common limited partners per unit	$ (24,048)	$ (52,194)

[1] In accordance with FSP EITF 03-6-1, net income (loss) attributable to common limited partners ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding).

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Diluted net loss attributable to common limited partners per unit is calculated by dividing net loss attributable to common limited partners, less loss 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 loss attributable to common limited partners per unit with those used to compute diluted net loss attributable to common limited partners per unit (in thousands):

	Three Months Ended March 31,	
	2009	2008
Weighted average common limited partners per unit - basic	45,971	38,763
Add effect of dilutive option incentive awards[(1)]		
Add effect of dilutive convertible preferred limited partner units[(1)]		
Weighted average common limited partners per unit - diluted	45,971	38,763

(1) 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. There were no unit options outstanding for the three months ended March 31, 2008. For the three months ended March 31, 2009 and 2008, 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 (see Note 5 for additional information regarding the conversion features of the preferred limited partner units).

Comprehensive Income (Loss)

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

	Three Months Ended March 31,	
	2009	2008
Net loss	$ (23,236)	$ (43,730)
Loss attributable to non-controlling interests	(469)	(2,090)
Preferred unit dividends	(900)	(137)
Preferred unit imputed dividend cost		(505)
Net loss attributable to common limited partners and the general partner	(24,605)	(46,462)
Other comprehensive loss:		
Changes in fair value of derivative instruments accounted for as hedges	(1,292)	18,585
Add: adjustment for realized losses reclassified to net loss	18,863	17,643
Total other comprehensive income	17,571	36,228
Comprehensive loss	$ (7,034)	$ (10,234)

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset s estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

Revenue Recognition

Revenue in the Partnership s Appalachia segment is principally recognized at the time the natural gas is transported through its gathering systems. Under the terms of its natural gas gathering agreements with Atlas Energy and its affiliates, the Partnership receives fees for gathering natural gas from wells owned by Atlas Energy and by drilling investment partnerships sponsored by Atlas Energy. The fees received for the gathering services under the Atlas Energy agreements are generally the greater of 16% of the gross sales price for natural gas produced from the wells, or $0.35 to $0.40 per thousand cubic feet (mcf), depending on the ownership of the well. Substantially all natural gas gathering revenue in the Appalachia segment is derived from these agreements. Fees for transportation services provided to independent third parties whose wells are connected to the Partnership s Appalachia gathering systems are at separately negotiated prices.

The Partnership s Mid-Continent segment revenue primarily consists of the fees earned from its transmission, 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 transports natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the Partnership s FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. 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:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. The Partnership s revenue is a function of the volume of natural gas that it gathers and processes and is not directly dependent on the value of the natural gas.

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 situation, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership owns a percentage of that commodity and is directly subject to its market value.

Keep-Whole Contracts. These contracts require the Partnership, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, the Partnership bears the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that it paid for the unprocessed natural gas. However, because the natural gas purchases contracted under keep-whole agreements are generally low in liquids content and meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with a portion of the Partnership s keep-whole contracts is minimized.

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The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership s records and management estimates of the related transportation 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, 2009 and December 31, 2008 of $44.3 million and $54.8 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within 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 4.8% and 6.7% for the three months ended March 31, 2009 and 2008, respectively, and the amount of interest capitalized was $1.4 million and $2.0 million for the three months ended March 31, 2009 and 2008, 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, 2009 and December 31, 2008 (in thousands):

	March 31, 2009	December 31, 2008	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	$ (6,204)	$ (5,806)	
Customer relationships	(41,920)	(35,929)	
	$ (48,124)	$ (41,735)	
Net Carrying Amount:			
Customer contracts	$ 6,606	$ 7,004	
Customer relationships	180,652	186,643	
	$ 187,258	$ 193,647	

Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets (SFAS No. 142) requires that intangible assets with finite useful lives be amortized 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 and residual values 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 periods ended March 31, 2009 and 2008. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2009 to 2012 - $25.6 million; 2013 - $24.5 million.

Goodwill

The changes in the carrying amount of goodwill for the three months ended March 31, 2009 and 2008 were as follows (in thousands):

	Three Months Ended March 31, 2009	2008
Balance, beginning of period	$	$ 709,283
Post-closing purchase price adjustment with seller and purchase price allocation adjustment - Chaney Dell and Midkiff/Benedum acquisition		(2,275)
Recovery of state sales tax initially paid on transaction Chaney Dell and Midkiff/Benedum acquisition		(30,206)
Balance, end of period	$	$ 676,802

As a result of its impairment evaluation at December 31, 2008, the Partnership recognized a $676.9 million non-cash impairment charge within its consolidated statements of operations during the fourth quarter of 2008. The goodwill impairment resulted from the reduction in the Partnership s estimated fair value of reporting units in comparison to their carrying amounts at December 31, 2008. The Partnership s estimated fair value of its reporting units was impacted by many factors, including the significant deterioration of commodity prices and global economic conditions during the fourth quarter of 2008. These estimates were subjective and based upon numerous assumptions about future operations and market conditions, which are subject to change.

During April 2008, the Partnership received a $30.2 million cash reimbursement for sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems in July 2007. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement of the sales tax received in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition at March 31, 2008.

Recently Adopted Accounting Standards

In June 2008, the FASB issued Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 applies to the calculation of earnings per share (EPS) described in paragraphs 60 and 61 of FASB Statement No. 128, Earnings per Share for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS pursuant to the two-class method. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption was prohibited. The Partnership adopted the requirements of FSP EITF 03-6-1 on January 1, 2009 and its adoption did not have a material impact on the Partnership s financial position and results of operations (see Net Income (Loss) Per Common Unit). Prior-period net loss per common limited partner unit data presented has been adjusted retrospectively to conform to the provisions of FSP EITF 03-6-1.

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In April 2008, the FASB issued Staff Position No. 142-3, Determination of Useful Life of Intangible Assets (FSP FAS 142-3). FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, Goodwill and Other Intangible Assets (SFAS 142). The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No 141(R), Business Combinations (SFAS No. 141(R)), and other U.S. Generally Accepted Accounting Principles. The Partnership adopted the requirements of FSP FAS 142-3 on January 1, 2009 and its adoption did not have a material impact on its financial position and results of operations.

In March 2008, the FASB ratified the EITF consensus on EITF Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF No. 07-4), an update of EITF No. 03-6, Participating Securities and the Two-Class Method Under FASB Statement No. 128 (EITF No. 03-6). EITF 07-4 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. EITF 07-4 also 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. The Partnership s adoption of EITF No. 07-4 on January 1, 2009 impacted its presentation of net income (loss) per common limited partner unit as the Partnership previously presented net income (loss) per common limited partner unit as though all earnings were distributed each quarterly period (see Net Income (Loss) Per Common Unit). Under the guidance of EITF 07-4, management of the Partnership believes that the partnership agreement contractually limits cash distributions to available cash and, therefore, undistributed earnings will no longer be allocated to the incentive distribution rights.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 161 amends the requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to require enhanced disclosure about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The Partnership adopted the requirements of SFAS No. 161 on January 1, 2009 and it did not have a material impact on its financial position or results of operations (see Note 9).

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidated Financial Statements-an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 amends ARB No. 51 to establish accounting and reporting standards for the non-controlling interest (minority interest) in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 also requires consolidated net income to be reported and disclosed on the face of the consolidated statement of operations at amounts that include the amounts attributable to both the parent and the non-controlling interest. Additionally, SFAS No. 160 establishes a single method of accounting for changes in a parent s ownership interest in a subsidiary that does not result in deconsolidation and that the parent recognize a gain or loss in net income when a subsidiary is deconsolidated. The Partnership adopted the requirements of SFAS No. 160 on January 1, 2009 and adjusted its presentation of its financial position and results of operations. Prior period financial position and results of operations have been adjusted retrospectively to conform to the provisions of SFAS No. 160.

In December 2007, the FASB issued SFAS No 141(R), Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) replaces SFAS No. 141, Business Combinations (SFAS No. 141), however retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) requires an acquirer to recognize the assets acquired, liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, at their fair values as of that date, with specified limited exceptions. Changes subsequent to that date are to be recognized in earnings, not goodwill. Additionally, SFAS No. 141 (R) requires costs incurred in connection with an acquisition be expensed as incurred. Restructuring costs, if any, are to be recognized separately from the acquisition. The acquirer in a business combination achieved in stages must also recognize the identifiable assets and liabilities, as well as the non-controlling interests in the acquiree, at the full amounts of their fair values. The Partnership adopted the requirements of SFAS No. 141(R) on January 1, 2009 and it did not have a material impact on its financial position and results of operations.

NOTE 3 ASSET SALE AGREEMENT

On March 31, 2009, the Partnership entered into an agreement with subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) to form a joint venture, Laurel Mountain Midstream, LLC (Laurel Mountain), that will own and operate the Partnership s Appalachia Basin natural gas gathering system, excluding the Partnership s Northern Tennessee operations. To the joint venture, Williams will contribute cash of $102.0 million, of which the Partnership will receive approximately $90.0 million, and a note receivable of $25.5 million. The Partnership will contribute the Appalachia Basin natural gas gathering system. The Partnership will retain a 49% ownership interest in the joint venture, as well as preferred distribution rights relating to all payments on the note receivable. Williams will retain the remaining 51% ownership interest in the joint venture. In addition, ATN will sell to the joint venture two natural gas processing plants and associated pipelines located in Southwestern Pennsylvania for $12.0 million. Upon the completion of the sale of the Partnership s Appalachia gathering systems to Laurel Mountain, Laurel Mountain will enter into new gas gathering agreements with Atlas Energy which will supersede the existing natural gas gathering agreements and omnibus agreement between the Partnership and Atlas Energy. Under the proposed gas gathering agreement, Atlas Energy will be obligated to pay Laurel Mountain all of the gathering fees it collects from its partnerships plus any excess amount over the amount of the competitive gathering fee (which is currently defined as 13% of the gross sales price received for the partnerships gas). The proposed gathering agreement contains additional provisions which define certain obligations and options of each party to build and connect newly drilled wells to any Laurel Mountain gathering system. The Partnership will account for its share of earnings associated with its ownership interest in Laurel Mountain under the equity method. The transaction is expected to close during the second quarter of 2009. The Partnership will use the net proceeds from the transaction to reduce borrowings under its senior secured credit facility (see Note 11).

NOTE 4 COMMON UNIT EQUITY OFFERINGS

In June 2008, the Partnership sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, the Partnership sold 1,112,000 common units to Atlas America and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. The Partnership also received a capital contribution from AHD of $5.4 million for AHD to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements (see Note 9).

NOTE 5 PREFERRED UNIT EQUITY OFFERINGS

Class A Preferred Units

At March 31, 2009, the Partnership had 20,000 $1,000 par value 12.0% cumulative convertible Class A preferred units of limited partner interests (the Class A Preferred Units) outstanding that are held by Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates. In January 2009, the Partnership and Sunlight Capital agreed to amend certain terms of the preferred units certificate of designation, which was

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initially entered into in March 2006. The amendment (a) increased the dividend yield from 6.5% to 12.0% per annum, effective January 1, 2009, (b) established a new conversion commencement date on the outstanding Class A Preferred Units of April 1, 2009, (c) established Sunlight Capital s new conversion option price of $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of the Partnership s common units, and (d) established a new price for the Partnership s call redemption right of $27.25.

The amendment to the preferred units certificate of designation also required that the Partnership issue Sunlight Capital $15.0 million of its 8.125% senior unsecured notes due 2015 (see Note 11) to redeem 10,000 Class A Preferred Units. Management of the Partnership estimated that the fair value of the $15.0 million 8.125% senior unsecured notes issued to redeem the Class A Preferred Units was approximately $10.0 million at the date of redemption based upon the market price of the publicly-traded senior notes. As such, the Partnership recorded the redemption by recognizing a $10.0 million reduction of Class A Preferred equity within Partners Capital, $15.0 million of additional long-term debt for the face value of the senior unsecured notes issued, and a $5.0 million discount on the issuance of the senior unsecured notes which is presented as a reduction of long-term debt on the Partnership s consolidated balance sheet. The discount recognized upon issuance of the senior unsecured notes will be amortized to interest expense in the Partnership s consolidated statements of operations over the term of the notes based upon the effective interest rate method.

The Partnership follows the provisions of SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity (SFAS No. 150). SFAS No. 150 states that financial instruments which are mandatorily redeemable shall be classified as a liability unless the redemption is required to occur only upon the liquidation or termination of the reporting entity. A financial instrument issued in the form of units is mandatorily redeemable if it embodies an unconditional obligation requiring the issuer to redeem the instrument by transferring assets at a specified or determinable date. The amendment of the preferred units certificate of designation required redemption of 15,000 of the Class A Preferred Units for cash in future periods. As such, the Partnership reclassified $15.0 million of the $20.0 million of Class A Preferred Units outstanding at March 31, 2009 from Class A Preferred Limited Partner equity within partners capital to preferred unit redemption obligation on its consolidated balance sheet. In addition, in April 2009, the Partnership and Sunlight Capital agreed that the Partnership would convert 5,000 of the Class A Preferred Units into Partnership common units. The Partnership will reclassify $5.0 million of the Class A Preferred Units from Class A preferred limited partner equity to common limited partner equity within partners capital when these preferred units are converted to common equity.

In accordance with Securities and Exchange Commission Staff Accounting Bulletin No. 68, Increasing Rate Preferred Stock, the initial issuances of the 40,000 Class A Preferred Units were recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. As a result of an amendment to the preferred units certificate of designation in March 2007, the Partnership, in lieu of dividend payments to Sunlight Capital, recognized an imputed dividend cost of $2.5 million that was amortized over a twelve-month period commencing March 2007 and was based upon the present value of the net proceeds received using the then-6.5% stated dividend yield. During the three months ended March 31, 2008, the Partnership amortized the remaining $0.5 million of this imputed dividend cost, which is presented as an additional adjustment of net income (loss) to determine net income (loss) attributable to common limited partners and the general partner on its consolidated statements of operations.

The Partnership recognized $0.5 million of preferred dividend cost for the three months ended March 31, 2009, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the general partner on its consolidated statements of operations. Of the $0.5 million of preferred dividend cost, $0.3 million was paid to Sunlight Capital on April 1, 2009 and $0.2 million was paid to Sunlight Capital on May 5, 2009. Sunlight Capital was entitled to receive dividends on the then-outstanding 40,000 Class A Preferred Units pro rata from the March 2008 commencement date. The Partnership recognized $0.1 million of preferred dividend cost for the three months ended March 31, 2008, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the general partner on its consolidated statements of operations, and paid this dividend on May 15, 2008.

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The outstanding Class A Preferred Units are reflected on the Partnership s consolidated balance sheet as Class A preferred equity within partners capital.

Class B Preferred Units

In December 2008, the Partnership sold 10,000 12.0% cumulative convertible Class B preferred units of limited partner interests (the Class B Preferred Units) to AHD for cash consideration of $1,000 per Class B Preferred Unit (the Face Value) pursuant to a certificate of designation (the Class B Preferred Units Certificate of Designation). On March 30, 2009, AHD, pursuant to its right within the Class B Preferred Unit Purchase Agreement, purchased an additional 5,000 Class B Preferred Units at Face Value. The Partnership used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for the Partnership s common units. The record date of determination for holders entitled to receive distributions of the Class B Preferred Units will be the same as the record date of determination for common unit holders entitled to receive quarterly distributions. Additionally, on March 30, 2009, the Partnership and AHD agreed to amend the terms of the Class B Preferred Units Certificate of Designation to remove the conversion feature, thus the Class B Preferred Units are not convertible into common units of the Partnership. The amended Class B Preferred Units Certificate of Designation also gives the Partnership the right at any time to redeem some or all of the outstanding Class B Preferred Units for cash at an amount equal to the Class B Preferred Unit Liquidation Value being redeemed, provided that such redemption must be exercised for no less than the lesser of a) 2,500 Class B Preferred Units or b) the number of remaining outstanding Class B Preferred Units.

The cumulative sale of the Class B Preferred Units to AHD was exempt from the registration requirements of the Securities Act of 1933. Dividends paid on the Class B Preferred Units and the premium paid upon the redemption of the Class B preferred units, if any, will be recognized as a reduction of the Partnership s net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. The Partnership recognized $0.5 million of preferred dividend cost for the three months ended March 31, 2009, which is presented as a reduction of net income (loss) to determine net income (loss) attributable to common limited partners and the general partner on its consolidated statements of operations. The $0.5 million preferred dividend is to be paid on May 15, 2009, the same scheduled date as the Partnership s quarterly cash distribution to common unitholders and the general partner (see Note 6). The Class B Preferred Units are reflected on the Partnership s consolidated balance sheet as Class B preferred equity within partners capital.

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, 2008 through March 31, 2009 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 14, 2008	December 31, 2007	$ 0.93	$ 36,051	$ 5,092
May 15, 2008	March 31, 2008	$ 0.94	$ 36,450	$ 7,891
August 14, 2008	June 30, 2008	$ 0.96	$ 44,096	$ 9,308
November 14, 2008	September 30, 2008	$ 0.96	$ 44,105	$ 9,312
February 13, 2009	December 31, 2008	$ 0.38	$ 17,463	$ 358

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In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems in July 2007, AHD, which holds all of the incentive distribution rights in the Partnership, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. AHD also agreed that the resulting allocation of incentive distribution rights back to the Partnership would be after AHD receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter.

On April 30, 2009, the Partnership declared a cash distribution of $0.15 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2009. The $7.3 million distribution, including $0.1 million to the General Partner, will be paid on May 15, 2009 to unitholders of record at the close of business on May 11, 2009.

NOTE 7 PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2009	December 31, 2008	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 2,025,920	$ 1,959,379	15 40
Rights of way	180,179	178,114	20 40
Buildings	8,968	8,968	40
Furniture and equipment	9,486	9,387	3 7
Other	14,066	13,812	3 10
	2,238,619	2,169,660	
Less accumulated depreciation	(165,102)	(146,723)	
	$ 2,073,517	$ 2,022,937	

No impairment charges were recorded during the three months ended March 31, 2009. During the three months ended March 31, 2008, the Partnership recognized an impairment charge totaling $4.0 million within asset impairment on its consolidated statements of operations in connection with a write-off of costs related to a pipeline expansion project. The costs incurred consisted of a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

NOTE 8 OTHER ASSETS

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

	March 31, 2009	December 31, 2008
Deferred finance costs, net of accumulated amortization of $18,315 and $17,298 at March 31, 2009 and December 31, 2008, respectively	$ 25,669	$ 23,676
Security deposits	1,605	1,419
Other	75	137
	$ 27,349	$ 25,232

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Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 11).

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 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 purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period.

The Partnership applies the provisions of SFAS No. 133 to its derivative instruments. The Partnership formally documents all relationships between hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching derivative contracts to the forecasted transactions. Under SFAS No. 133, the Partnership can assess, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying item being hedged, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by the Partnership through the utilization of market data, will be recognized within other income (loss), net in its consolidated statements of operations. For derivatives previously qualifying as hedges, the Partnership recognized the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss) and reclassified the portion relating to commodity derivatives to natural gas and liquids revenue and the portion relating to interest rate derivatives to interest expense within its consolidated statements of operations as the underlying transactions were settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, the Partnership recognizes changes in fair value within other income (loss), net in its consolidated statements of operations as they occur.

Beginning July 1, 2008, the Partnership discontinued hedge accounting for its existing commodity derivatives which were qualified as hedges under SFAS No. 133. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), 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.

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During the three months ended March 31, 2009 and year ended December 31, 2008, the Partnership made net payments of $5.0 million and $274.0 million, respectively, related to the early termination of derivative contracts. Substantially all of these derivative contracts were put into place simultaneously with the Partnership s acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. During the three months ended March 31, 2009 and 2008, the Partnership recognized the following derivative activity related to the termination of these derivative instruments within its consolidated statements of operations (amounts in thousands):

	Early Termination of Derivative Contracts for the Three Months Ended March 31, 2009	2008
Net cash derivative expense included within other income (loss), net	$ (5,000)	$
Net cash derivative expense included within natural gas and liquids revenue		
Net non-cash derivative income included within other income (loss), net	12,103	
Net non-cash derivative expense included within natural gas and liquids	(21,944)	

In addition, $25.3 million will be reclassified from accumulated other comprehensive loss within partner s capital on the Partnership s consolidated balance sheet and recognized as non-cash derivative expenses during the period beginning on April 1, 2009 and ending on December 31, 2009, the remaining period for which the derivatives were originally scheduled to be settled, as a result of the early termination of certain derivatives that were classified as cash flow hedges in accordance with SFAS No. 133 at the date of termination.

At March 31, 2009, the Partnership had interest rate derivative contracts having aggregate notional principal amounts of $450.0 million, which were designated as cash flow hedges. Under the terms of these agreements, the Partnership will pay weighted average interest rates of 3.02%, plus the applicable margin as defined under the terms of its revolving credit facility (see Note 11), and will receive LIBOR, plus the applicable margin, on the notional principal amounts. These derivatives effectively convert $450.0 million of the Partnership s floating rate debt under the term loan and revolving credit facility to fixed-rate debt. The interest rate swap agreements were effective as of March 31, 2009 and expire during periods ranging from January 30, 2010 through April 30, 2010.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. At March 31, 2009 and December 31, 2008, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $89.9 million and $63.6 million, respectively. Of the $87.4 million of net loss in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet at March 31, 2009, if the fair values of the instruments remain at current market values, the Partnership will reclassify $44.0 million of losses to the Partnership s consolidated statements of operations over the next twelve month period, consisting of $34.4 million of losses to natural gas and liquids revenue and $9.6 million of losses to interest expense. Aggregate losses of $43.4 million will be reclassified to the Partnership s consolidated statements of operations in later periods, consisting of $42.9 million of losses to natural gas and liquids revenue and $0.5 million of losses to interest expense. Actual amounts that will be reclassified will vary as a result of future price or interest rate changes.

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

	March 31, 2009	December 31, 2008
Current portion of derivative asset	$	$ 44,961
Long-term derivative asset		
Current portion of derivative liability	(66,698)	(60,396)
Long-term derivative liability	(23,210)	(48,159)
	$ (89,908)	$ (63,594)

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The following table summarizes the Partnership s derivative activity for the periods indicated (amounts in thousands):

	Three Months Ended March 31,	
	2009	2008
Loss from cash and non-cash settlement of qualifying hedge instruments(1)	$ (20,175)	$ (17,643)
Loss from change in market value of non-qualifying derivatives(2)	(44,990)	(71,196)
Gain (loss) from change in market value of ineffective portion of qualifying derivatives(2)	10,813	(5,660)
Gain (loss) from cash and non-cash settlement of non-qualifying derivatives(2)	34,495	(11,925)
Loss from cash settlement of interest rate derivatives(3)	(2,893)	

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

(2) Included within other income (loss), net on the Partnership s consolidated statements of operations.

(3) Included within interest expense on the Partnership s consolidated statements of operations.

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

	March 31, 2009			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments under SFAS No. 133:				
Interest rate contracts	Current portion of derivative asset	$	Current portion of derivative liability	$ (9,685)
Interest rate contracts	Long-term derivative asset		Long-term derivative liability	(442)
Derivatives not designated as hedging instruments under SFAS No. 133:				
Commodity contracts	Current portion of derivative liability	3,977	Current portion of derivative liability	(60,991)
Commodity contracts	Long-term derivative liability	2,380	Long-term derivative liability	(25,147)
		$ 6,357		$ (96,265)

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The following table summarizes the gross effect of derivative instruments on the Partnership s consolidated statement of operations for the period indicated (amounts in thousands):

	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	March 31, 2009 Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Location of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
Derivatives in SFAS No. 133 cash flow hedging relationships:				
Interest rate contracts	$ (2,893)	Interest expense	$	N/A
Derivatives not designated as hedging instruments under SFAS No. 133:				
Commodity contracts(1)	$ (15,970)	Natural gas and liquids revenue	$ (9,527)	Other income (loss), net
Commodity contracts(2)			39,820	Other income (loss), net
	$ (18,863)		$ 30,293	

(1) Hedges previously designated as cash flow hedges

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

As of March 31, 2009, the Partnership had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Term	Notional Amount	Type		Contract Period Ended December 31,	Fair Value Liability(1) (in thousands)
January 2008 - January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	2009	$ (3,374)
				2010	(304)
					$ (3,678)
April 2008 - April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2009	$ (4,715)
				2010	(1,734)
					$ (6,449)

Natural Gas Liquids Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Asset(2)

	(gallons)	(per gallon)	(in thousands)
2009	13,230,000	$ 0.745	$ 1,579

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)[1] (in thousands)	Option Type
2009	152,100	13,542,984	$ 111.53	$ (11,171)	Puts sold[4]
2009	152,100	13,542,984	$ 157.82		Calls purchased[4]
2009	1,588,500	88,643,058	$ 84.69	(2,019)	Calls sold
2010	3,127,500	213,088,050	$ 86.20	(13,035)	Calls sold
2010	714,000	45,415,440	$ 132.17	638	Calls purchased[4]
2011	606,000	33,145,560	$ 100.70	(3,071)	Calls sold
2011	252,000	13,547,520	$ 133.16	665	Calls purchased[4]
2012	450,000	25,893,000	$ 102.71	(2,822)	Calls sold
2012	180,000	9,676,800	$ 134.27	657	Calls purchased[4]
				$ (30,158)	

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Natural Gas Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Asset (3) (in thousands)
2009	360,000	$ 8.000	$ 1,337

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Asset (3) (in thousands)
2009	3,690,000	$ (0.558)	$ 673
2010	2,220,000	$ (0.575)	301
			$ 974

Natural Gas Purchases Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Liability(3) (in thousands)
2009	7,740,000	$ 8.687	$ (34,069)
2010	4,380,000	$ 8.635	(12,806)
			$ (46,875)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Liability(3) (in thousands)
2009	11,070,000	$ (0.659)	$ (2,837)
2010	6,600,000	$ (0.560)	(1,783)
			$ (4,620)

Ethane Put Options

Production Period Ended December 31,	Associated NGL Volume	Average Crude Strike Price	Fair Value Asset(1)	Option Type

	(gallons)	(per gallon)	(in thousands)	
2009	630,000	$ 0.340	$ 12	Puts purchased

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Isobutane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(1) (in thousands)	Option Type
2009	126,000	$ 0.589	$ (10)	Puts purchased

Normal Butane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(1) (in thousands)	Option Type
2009	126,000	$ 0.577	$ (10)	Puts purchased

Natural Gasoline Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(1) (in thousands)	Option Type
2009	126,000	$ 0.762	$ (10)	Puts purchased

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Asset(3) (in thousands)
2009	24,000	$ 62.700	$ 206

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability(1) (in thousands)	Option Type
2009	229,500	$ 84.802	$ (314)	Calls sold
2010	234,000	$ 88.088	(912)	Calls sold
2011	72,000	$ 93.109	(502)	Calls sold
2012	48,000	$ 90.314	(478)	Calls sold
			$ (2,206)	

Total net liability	$	(89,908)

(1) Fair value based on independent, third-party statements, supported by observable levels at which transactions are executed in the marketplace.

(2) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas, light crude and propane prices.

(3) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

(4) Puts sold and calls purchased for 2009 represent costless collars entered into by the Partnership as offsetting positions for the calls sold related to ethane and propane production. In addition, calls were purchased for 2010 through 2012 to offset 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.

(5) Mmbtu represents million British Thermal Units.

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NOTE 10 FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership applies the provisions of SFAS No. 157, Fair Value Measurements (SFAS No. 157) to its financial instruments. SFAS No. 157 establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. SFAS No. 157 s 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.

The Partnership uses the fair value methodology outlined in SFAS No. 157 to value the assets and liabilities for its respective outstanding derivative contracts (see Note 9). All of the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and crude oil options. The Partnership s Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. 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 natural gas, crude oil, and propane prices, and therefore are defined as Level 3. Valuations for the Partnership s crude oil options (including those associated with NGL sales) are based on forward price curves developed by the related financial institution based upon current quoted prices for crude oil futures, and therefore are defined at Level 3. In accordance with SFAS No. 157, the following table represents the Partnership s assets and liabilities recorded at fair value as of March 31, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total
Commodity-based derivatives	$	$ (48,978)	$ (30,803)	$ (79,781)
Interest rate swap-based derivatives		(10,127)		(10,127)
Total	$	$ (59,105)	$ (30,803)	$ (89,908)

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and crude oil options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments as of March 31, 2009 (in thousands):

	NGL Fixed Price Swaps	Crude Oil Sales Options (associated with NGL Volume)	Crude Oil Sales Options	NGL Sales Options	Total
Balance December 31, 2008	$ 1,509	$ (15,867)	$ (7,569)	$ 12,316	$ (9,611)
New options contracts	459				459
Cash settlements from unrealized gain (loss)[1]	(2,240)	(30,189)	(7,482)	(11,410)	(51,321)
Cash settlements from other comprehensive income[1]	1,895	7,952	3,666		13,513
Net change in unrealized gain (loss)[2]	(44)	9,008	5,878	(982)	13,860
Deferred option premium recognition		(1,062)	3,301	58	2,297
Net change in other comprehensive loss					
Balance March 31, 2009	$ 1,579	$ (30,158)	$ (2,206)	$ (18)	$ (30,803)

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

(2) Included within other income (loss), net on the Partnership s consolidated statements of operations.

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NOTE 11 DEBT

Total debt consists of the following (in thousands):

	March 31, 2009	December 31, 2008
Revolving credit facility	$ 324,000	$ 302,000
Term loan	707,180	707,180
8.125% Senior notes due 2015	271,173	261,197
8.75% Senior notes due 2018	223,050	223,050
Total long term debt	1,525,403	1,493,427
Less current maturities		
Total debt	$ 1,525,403	$ 1,493,427

Term Loan and Credit Facility

At March 31, 2009, the Partnership 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 the Partnership s 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). The weighted average interest rate on the outstanding revolving credit facility borrowings at March 31, 2009 was 2.8%, and the weighted average interest rate on the outstanding term loan borrowings at March 31, 2009 was 3.3%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $5.4 million was outstanding at March 31, 2009. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet.

In June 2008, the Partnership entered into an amendment to its revolving credit facility and term loan agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to the Partnership s early termination of certain derivative contracts (see Note 9) in calculating its Consolidated EBITDA. Pursuant to this amendment, in June 2008, the Partnership repaid $122.8 million of its outstanding term loan and repaid $120.0 million of outstanding borrowings under the credit facility with proceeds from its issuance of $250.0 million of 10-year, 8.75% senior unsecured notes (see Senior Notes). Additionally, pursuant to this amendment, in June 2008 the Partnership s lenders increased their commitments for the revolving credit facility by $80.0 million to $380.0 million.

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 the Chaney Dell and Midkiff/Benedum joint ventures, and by the guaranty of each of its 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 in compliance with these covenants as of March 31, 2009. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt and equity issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with entering into the credit facility, the Partnership agreed to remit an underwriting fee to the lead underwriting bank based upon the aggregate principal amount of the term loan outstanding, subject to adjustments as stated in the agreement. The Partnership recorded an obligation for this fee of approximately $2.9 million within other assets and accrued liabilities on its consolidated balance sheet at March 31, 2009. The Partnership has recognized this amount as a non-cash transaction within its consolidated statement of cashflows for the three months ended March 31, 2009.

The events which constitute an event of default for the Partnership s credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, 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 a ratio of funded debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.75 to 1.0. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of March 31, 2009, the Partnership s ratio of funded debt to EBITDA was 4.9 to 1.0 and its interest coverage ratio was 4.0 to 1.0.

The Partnership is 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.

Senior Notes

At March 31, 2009, 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 $270.5 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 $0.6 million of unamortized premium received as of March 31, 2009. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time 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.

In January 2009, the Partnership issued Sunlight Capital $15.0 million of its 8.125% Senior Notes to redeem 10,000 Class A Preferred Units (see Note 5). Management of the Partnership estimated that the fair value of the $15.0 million 8.125% Senior Notes issued was approximately $10.0 million at the date of issuance based upon the market price of the publicly-traded Senior Notes. As such, the Partnership recognized a $5.0 million discount on the issuance of the Senior Notes, which will be presented as a reduction of long-term debt on its consolidated balance sheets. The discount recognized upon issuance of the Senior Notes will be amortized to interest expense in the Partnership s consolidated statements of operations over the term of the 8.125% Senior Notes based upon the effective interest rate method.

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, 2009.

In connection with the issuance of the 8.75% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If the Partnership did not meet the aforementioned deadline, the 8.75% Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that the Partnership had caused the exchange offer to be consummated. On November 21, 2008, the Partnership filed an exchange offer registration statement for the 8.75% Senior Notes with the Securities and Exchange Commission, which was declared effective on December 16, 2008. The exchange offer was consummated on January 21, 2009, thereby fulfilling all of the requirements of the 8.75% Senior Notes registration rights agreement by the specified dates.

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.

As of March 31, 2009, the Partnership is committed to expend approximately $56.7 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

In January 2009, in the matter captioned Elk City Oklahoma Pipeline, L.P. v. Northern Natural Gas Company , (District Court of Tulsa County, Oklahoma), Elk City Oklahoma Pipeline, L.P. (Elk City), a subsidiary of the Partnership, filed a petition against Northern Natural Gas Company (NNG), seeking a declaratory judgment related to the interpretation of a Purchase and Sale Agreement for certain pipeline and assets in Western Oklahoma which was entered into between the two parties on June 12, 2008 (the PSA). In March 2009, NNG filed a petition together with a motion for summary judgment alleging breach of the PSA for Elk City s failure to complete the purchase and seeking specific performance or, alternatively, damages, in the matter captioned Northern Natural Gas Company vs. Elk City Oklahoma Pipeline, L.P. , (District Court of Tulsa County, Oklahoma). Both matters are currently pending. The Partnership believes that the claims are without merit and intends to pursue its action and defend against NNG s claims. Additionally, the Partnership believes that the ultimate resolution of these matters will not have a material impact on its financial position and results of operations.

NOTE 13 STOCK COMPENSATION

Long-Term Incentive Plan

The Partnership has a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner s affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by 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, without payment of an exercise price, upon vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. 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

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phantom unit is outstanding. A unit option entitles the grantee to purchase the Partnership s common limited partner units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through March 31, 2009, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. 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, 2009, 31,607 units will vest within the following twelve months. All phantom units outstanding under the LTIP at March 31, 2009 include DERs granted to the participants by the Committee. The amounts paid with respect to LTIP DERs were $0.1 million for the three months ended March 31, 2009 and 2008, respectively. These amounts were recorded as reductions of Partners Capital on the Partnership s consolidated balance sheet.

The Partnership follows the provisions of SFAS No. 123(R), Share-Based Payment , as revised (SFAS No. 123(R)). Generally, the approach to accounting in SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values.

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

	Three Months Ended March 31,	
	2009	2008
Outstanding, beginning of period	126,565	129,746
Granted[1]	1,500	53,951
Matured[2]	(9,886)	(11,860)
Forfeited	(16,250)	(750)
Outstanding, end of period[3]	101,929	171,087
Non-cash compensation (income) expense recognized (in thousands)	$ (95)	$ 486

(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 $4.60 and $44.44 for awards granted for the three months ended March 31, 2009 and 2008, respectively.

(2) The intrinsic values for phantom unit awards exercised during the three months ended March 31, 2009 and 2008 were $0.1 million and $0.2 million, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at March 31, 2009 was $0.4 million.

At March 31, 2009, the Partnership had approximately $1.4 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 Participant to receive a common unit of the Partnership upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option may be equal to or more than the fair market value of the Partnership s common unit as determined by the Committee 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

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period for unit options. Unit option awards expire 10 years from the date of grant. Through March 31, 2009, unit options granted under the Partnership s LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. 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, 2009 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, 2009		2008	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period				
Granted	100,000	$ 6.24		
Matured				
Forfeited				
Outstanding, end of period[(1)(2)]	100,000	$ 6.24		
Options exercisable, end of period[(3)]				
Weighted average fair value of unit options per unit granted during the period	100,000	$ 0.14		
Non-cash compensation expense recognized (in thousands)	$ 2		$	

(1) The weighted average remaining contractual life for outstanding options at March 31, 2009 was 9.8 years.

(2) There was no aggregate intrinsic value of options outstanding at March 31, 2009.

(3) There were no options exercised during the three months ended March 31, 2009 and 2008, respectively.

At March 31, 2009, the Partnership had approximately $12,000 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%
Risk-free interest rate	2.2%
Expected term (in years)	6.3

Incentive Compensation Agreements

The Partnership had incentive compensation agreements which granted awards to certain key employees retained from previously consummated acquisitions. These individuals were entitled to receive common units of the Partnership upon the vesting of the awards, which was dependent upon the achievement of certain predetermined performance targets through September 30, 2007. At September 30, 2007, the predetermined performance targets were achieved and all of the awards under the incentive compensation agreements vested. Of the total common units issued under the incentive compensation agreements, 58,822 common units were issued during the year ended December 31, 2007. The ultimate number of common units issued under the incentive compensation agreements was determined principally by the financial performance of certain Partnership assets during the year ended December 31, 2008 and the market value of the Partnership s common units at December 31, 2008. The incentive compensation agreements also dictated that no individual covered under the agreements would receive an amount of common units in excess of one percent of the outstanding common units of the Partnership at the date of issuance. Common unit amounts due to any individual covered under the agreements in excess of one percent of the outstanding common units of the Partnership would have been paid in cash.

As of December 31, 2008, the Partnership recognized in full within its consolidated statements of operations the compensation expense associated with the vesting of awards issued under these incentive compensation agreements, therefore no compensation expense was recognized during the three months ended March 31, 2009. The Partnership recognized a reduction of compensation expense of $3.3 million for the three months ended March 31, 2008 related to the vesting of awards under these incentive compensation agreements. The non-cash compensation expense adjustments for the three months ended March 31, 2008 were principally attributable to changes in the Partnership s common unit market price, which was utilized in the calculation of the non-cash compensation expense for these awards, at March 31, 2008 when compared with the common unit market price at earlier periods and adjustments based upon the achievement of actual financial performance targets through March 31, 2008. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method. During the three months ended March 31, 2009, the Partnership issued 209,172 common units to the certain key employees covered under the incentive compensation agreements. The Partnership will issue an additional 139,448 common units during the second quarter 2009 to fulfill its obligations under the terms of the agreements. No additional common units will be issued with regard to these agreements.

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 America. 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 their 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 America based on the number of its employees who devote their time to activities on the Partnership s behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses 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 and $1.1 million for the three months ended March 31, 2009 and 2008, respectively, for compensation and benefits related to their employees. There were no direct reimbursements to the General Partner and its affiliates for the three months ended March 31, 2009 and 2008. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

Under an agreement between the Partnership and Atlas Energy, Atlas Energy must construct up to 2,500 feet of sales lines from its existing wells in the Appalachian region to a point of connection to the Partnership s gathering systems. The Partnership must, at its own cost, extend its system to connect to any such lines within 1,000 feet of its gathering systems. With respect to wells to be drilled by Atlas Energy that will be more than 3,500 feet from the Partnership s gathering systems, the Partnership has various options to connect those wells to its gathering systems at its own cost.

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NOTE 15 SEGMENT INFORMATION

The Partnership has two reportable segments: natural gas transmission, gathering and processing located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee, and transmission, gathering and processing located in the Mid-Continent area (Mid-Continent) of primarily Oklahoma, northern and western Texas, the Texas Panhandle, Arkansas, southern Kansas and southeastern Missouri. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and transport of natural gas. These reportable segments reflect the way the Partnership manages its operations.

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

	Three Months Ended March 31,	
	2009	**2008**
Mid-Continent		
Revenue:		
Natural gas and liquids	$ 158,247	$ 365,159
Transportation, compression and other fees	16,031	14,615
Other income (loss), net	5,075	(86,865)
Total revenue and other income (loss), net	179,353	292,909
Costs and expenses:		
Natural gas and liquids	137,870	276,182
Plant operating	13,823	14,935
Transportation and compression	1,436	1,498
General and administrative	8,655	2,530
Depreciation and amortization	22,761	20,462
Asset impairment		3,981
Total costs and expenses	184,545	319,588
Segment loss	(5,192)	$ (26,679)
Appalachia		
Revenue:		
Natural gas and liquids	$ 371	$ 960
Transportation, compression and other fees affiliates	10,068	9,159
Transportation, compression and other fees third parties	381	247
Other income, net	73	111
Total revenue and other income, net	10,893	10,477
Costs and expenses:		
Natural gas and liquids	189	482
Transportation and compression	3,331	2,314
General and administrative	1,182	1,484
Depreciation and amortization	1,919	1,382
Total costs and expenses	6,621	5,662
Segment profit	$ 4,272	$ 4,815

<u>Reconciliation of segment profit (loss) to net loss</u>:		
Segment profit (loss):		
Mid-Continent	$ (5,192)	$ (26,679)
Appalachia	4,272	4,815
Total segment loss	(920)	(21,864)
Corporate general and administrative expenses	(1,182)	(1,485)
Interest expense[(1)]	(21,134)	(20,381)
Net loss	$ (23,236)	$ (43,730)
<u>Capital Expenditures</u>:		
Mid-Continent	$ 67,667	$ 69,683
Appalachia	5,246	14,386
	$ 72,913	$ 84,069

(1) The Partnership notes that interest expense has not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

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	March 31, 2009	December 31, 2008
Balance Sheet		
Total assets:		
Mid-Continent	$ 2,237,221	$ 2,274,290
Appalachia	117,587	114,166
Corporate other	27,423	24,740
	$2,382,231	$2,413,196

The following tables summarize the Partnership s total revenues by product or service for the periods indicated (in thousands):

	Three Months Ended March 31,	
	2009	2008
Natural gas and liquids:		
Natural gas	$ 77,598	$ 139,783
NGLs	66,294	198,693
Condensate	794	12,680
Other(1)	13,932	14,963
Total	$ 158,618	$ 366,119
Transportation, compression and other fees:		
Affiliates	$ 10,068	$ 9,159
Third parties	16,412	14,862
Total	$ 26,480	$ 24,021

(1) Includes treatment, processing, and other revenue associated with the products noted.

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, 2009 and December 31, 2008 and for the three months ended March 31, 2009 and 2008 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 (see Note 2). 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, 2009 and December 31, 2008 and for the three months ended March 31, 2009 and 2008. 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, 2009				
Balance Sheet	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$ 7	$ 1,905	$	$	$ 1,912
Accounts receivable affiliates	1,430,615			(1,430,615)	
Other current assets		42,067	50,128		92,195
Total current assets	1,430,622	43,972	50,128	(1,430,615)	94,107
Property, plant and equipment, net		963,127	1,110,390		2,073,517
Notes receivable			1,852,928	(1,852,928)	
Equity investments	735,274	574,930		(1,310,204)	
Intangible assets, net		20,450	166,808		187,258
Other assets, net	25,670	1,497	182		27,349
	$ 2,191,566	$ 1,603,976	$ 3,180,436	$ (4,593,747)	$ 2,382,231
Liabilities and Partners Capital					
Accounts payable affiliates	$	$ 1,338,555	$ 104,460	$ (1,430,615)	$ 12,400
Current portion of derivative liability		66,698			66,698
Other current liabilities	27,143	61,260	57,722		146,125
Total current liabilities	27,143	1,466,513	162,182	(1,430,615)	225,223
Long-term derivative liability		23,210			23,210
Long-term debt	1,525,403				1,525,403
Other long-term liability		533			533
Partners capital	639,020	113,720	3,018,254	(3,163,132)	607,862
	$ 2,191,566	$ 1,603,976	$ 3,180,436	$ (4,593,747)	$ 2,382,231

	December 31, 2008				
Balance Sheet	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$ 7	$ 1,513	$	$	$ 1,520
Accounts receivable affiliates	1,444,812			(1,444,275)	537
Current portion of derivative asset		44,961			44,961
Other current assets		50,385	73,977		124,362

Total current assets	1,444,819	96,859	73,977	(1,444,275)	171,380
Property, plant and equipment, net		923,423	1,099,514		2,022,937
Notes receivable			1,852,928	(1,852,928)	
Equity investments	709,981	194,291		(904,272)	
Intangible assets, net		21,063	172,584		193,647
Other assets, net	23,676	1,374	182		25,232
	$ 2,178,476	$ 1,237,010	$ 3,199,185	$ (4,201,475)	$ 2,413,196
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,362,256	$ 82,019	$ (1,444,275)	$
Current portion of derivative liability		60,396			60,396
Other current liabilities	1,870	66,677	91,251		159,798
Total current liabilities	1,870	1,489,329	173,270	(1,444,275)	220,194
Long-term derivative liability		48,159			48,159
Long-term debt	1,493,427				1,493,427
Other long-term liability		574			574
Partners capital (deficit)	683,179	(301,052)	3,025,915	(2,757,200)	650,842
	$ 2,178,476	$ 1,237,010	$ 3,199,185	$ (4,201,475)	$ 2,413,196

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		Three Months Ended March 31, 2009			
Statement of Operations	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Total revenue and other income (loss), net	$	$ 72,071	$ 135,356	$ (17,181)	$ 190,246
Total costs and expenses	(21,134)	(91,994)	(117,535)	17,181	(213,482)
Equity income (loss)	(2,087)	18,304		(16,217)	
Net income (loss)	$ (23,221)	$ (1,619)	$ 17,821	$ (16,217)	$ (23,236)

		Three Months Ended March 31, 2008			
Statement of Operations	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Total revenue and other income (loss), net	$	$ 43,760	$ 259,626	$	$ 303,386
Total costs and expenses	(5,945)	(149,798)	(191,373)		(347,116)
Equity income (loss)	(25,248)	68,444		(43,196)	
Net income (loss)	$ (31,193)	$ (37,594)	$ 68,253	$ (43,196)	$ (43,730)

		Three Months Ended March 31, 2009			
Statement of Cash Flows	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Cashflows from operating activities:					
Net income (loss)	$ (23,221)	$ (1,619)	$ 17,821	$ (16,217)	$ (23,236)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Depreciation and amortization		9,855	14,825		24,680
Non-cash loss on derivative value, net		43,885			43,885
Non-cash compensation income	(93)				(93)
Amortization of deferred financing costs	1,017				1,017
Net distributions to non-controlling interest holders		710			710
Changes in assets and liabilities net of effects of acquisitions	38,633	17,741	(6,493)	(32,403)	17,478
Net cash provided by (used in) operating activities	16,336	70,572	26,153	(48,620)	64,441
Net cash provided by (used in) investing activities	(25,293)	(430,533)	(23,112)	405,932	(73,006)
Net cash provided by (used in) financing activities	8,957	360,353	(3,041)	(357,312)	8,957
Net increase in cash and cash equivalents		392			392
Cash and cash equivalents, beginning of period	7	1,513			1,520
Cash and cash equivalents, end of period	$ 7	$ 1,905	$	$	$ 1,912

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			Three Months Ended March 31, 2008		
Statement of Cash Flows	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Cashflows from operating activities:					
Net income (loss)	$ (31,193)	$ (37,594)	$ 68,253	$ (43,196)	$ (43,730)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization		7,544	14,300		21,844
Asset impairment		3,981			3,981
Non-cash loss on derivative value, net		74,814			74,814
Non-cash compensation income	(2,795)				(2,795)
Gain on asset sales and dispositions		(132)			(132)
Amortization of deferred financing costs	679				679
Net distributions to non-controlling interest holders		(413)			(413)
Changes in assets and liabilities net of effects of acquisitions	68,229	(34,589)	42,158	(75,168)	630
Net cash provided by operating activities	34,920	13,611	124,711	(118,364)	54,878
Net cash provided by (used in) investing activities	(53,659)	17,983	(15,516)	(31,847)	(83,039)
Net cash provided by (used in) financing activities	18,739	(22,970)	(127,244)	150,211	18,736
Net increase (decrease) in cash and cash equivalents		8,624	(18,049)		(9,425)
Cash and cash equivalents, beginning of period	7	(6,076)	18,049		11,980
Cash and cash equivalents, end of period	$ 7	$ 2,548	$	$	$ 2,555

NOTE 17 SUBSEQUENT EVENTS

On May 5, 2009, the Partnership redeemed the remaining 5,000 of the Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $5.0 million, pursuant to the terms of the amended preferred units certificate of designation (see Note 5). Additionally on May 5, 2009, the Partnership paid Sunlight a preferred dividend of $0.2 million, representing the quarterly dividend on the 5,000 Class A Preferred Units held by Sunlight prior to the Partnership s redemption.

On April 7, 2009, the Partnership entered into an agreement with Spectra Energy Partners OLP, LP (NYSE: SEP) (Spectra) related to the sale of the NOARK gas gathering and interstate pipeline system, including Ozark Gas Transmission, LLC and Ozark Gas Gathering, LLC, for $300.0 million cash. The purchase price will be subject to an adjustment based on the working capital of the NOARK system during the periods between the signing date and closing dates. The Partnership will account for the sale of the NOARK system assets as discontinued operations within its consolidated financial statements in the future. The transaction closed on May 4, 2009 and the Partnership used the net proceeds from the transaction to reduce borrowings under its senior secured term loan and credit facility (see Note 11).

On April 1, 2009, the Partnership redeemed 10,000 of the Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $10.0 million, pursuant to the terms of the amended preferred units certificate of designation (see Note 5). Additionally on April 1, 2009, the Partnership paid Sunlight a preferred dividend of $0.3 million, representing the quarterly dividend on the 10,000 Class A Preferred Units held by Sunlight prior to the Partnership s redemption. On April 13, 2009, Sunlight exercised its right to convert 5,000 Class A Preferred Units into 1,465,653 common limited partner units, which was based on 95% of the market value of the Partnership s closing common unit price for the 10 business days prior to and including March 31, 2009.

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 2008. 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 whose common units are listed on the New York Stock Exchange under the symbol APL . Our principal business objective is to generate cash for distribution to our unitholders. We are a leading provider of natural gas gathering services in the Anadarko, Arkoma, and Permian Basins and the Golden Trend in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing and treatment services in Oklahoma and Texas. We also provide interstate gas transmission services in southeastern Oklahoma, Arkansas, southern Kansas and southeastern Missouri. Our business is conducted in the midstream segment of the natural gas industry through two reportable segments: our Mid-Continent operations and our Appalachian operations.

As of March 31, 2009, through our Mid-Continent operations, we own and operate:

- a FERC-regulated, 565-mile interstate pipeline system (Ozark Gas Transmission) that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and which has throughput capacity of approximately 500 MMcfd;

- eight active natural gas processing plants with aggregate capacity of approximately 810 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, located in Oklahoma and Texas; and

9,100 miles of active natural gas gathering systems located in Oklahoma, Arkansas, Kansas and Texas, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing and treating plants or Ozark Gas Transmission, as well as third party pipelines.

As of March 31, 2009, through our Appalachian operations, we own and operate 1,835 miles of natural gas gathering systems located in eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee. Through an omnibus agreement and other agreements between us and Atlas America, Inc. (Atlas America NASDAQ: ATLS) and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin and a publicly-traded company (NYSE: ATN), we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. Among other things, the omnibus agreement requires Atlas Energy to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America and Atlas Energy under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport.

Recent Events

On March 31, 2009, we entered into an agreement with subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) to form a joint venture, Laurel Mountain Midstream, LLC (Laurel Mountain), that will own and operate our Appalachia Basin natural gas gathering system, excluding our northern Tennessee operations. To the joint venture, Williams will contribute cash of $102.0 million, of which we will receive approximately $90.0 million, and a note receivable of $25.5 million. We will contribute the Appalachia Basin natural gas gathering system. We will retain a 49% ownership interest in the joint venture, as well as preferred distribution rights relating to all payments on the note receivable. Williams will retain the remaining 51% ownership interest in the joint venture. In addition, ATN will sell to the joint venture two natural gas processing plants and associated pipelines located in Southwestern Pennsylvania for $12.0 million. Upon the completion of the sale of our Appalachia gathering systems to Laurel Mountain, Laurel Mountain will enter into new gas gathering agreements with Atlas Energy which will supersede the existing natural gas gathering agreements and omnibus agreement between us and Atlas Energy. Under the proposed gas gathering agreement, Atlas Energy will be obligated to pay Laurel Mountain all of the gathering fees it collects from its partnerships plus any excess amount over the amount of the competitive gathering fee (which is currently defined as 13% of the gross sales price received for the partnerships gas). The proposed gathering agreement contains additional provisions which define certain obligations and options of each party to build and connect newly drilled wells to any Laurel Mountain gathering system. We will account for our share of earnings associated with our ownership interest in the joint venture under the equity method. The transaction is expected to close during the second quarter of 2009. We will use the net proceeds from the transaction to reduce borrowings under its senior secured credit facility (see Term Loan and Credit Facility).

On March 30, 2009, Atlas Pipeline Holdings, L.P., the parent of our general partner (AHD), pursuant to its right within the Class B Preferred Unit Purchase Agreement, purchased an additional 5,000 of our 12% Class B Preferred Units of limited partner interest (the Class B Preferred Units) for cash consideration of $1,000 per Class B Preferred Unit. We used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units will receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for our common units (see Preferred Units Class B Preferred Units). Additionally, on March 30, 2009, we and AHD agreed to amend the terms of the Class B Preferred Units Certificate of Designation to remove the conversion feature, thus the Class B Preferred Units are not convertible into our common units. The amended Class B Preferred Units Certificate of Designation also gives us the right at any time to redeem some or all of the outstanding Class B Preferred Units for cash, or an amount equal to the Class B Preferred Unit Liquidation Value being redeemed, provided that such redemption must be exercised for no less than the lesser of a) 2,500 Class B Preferred Units or b) the number of remaining outstanding Class B Preferred Units.

In January 2009, we and Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, agreed to amend certain terms of our Class A Preferred Units Certificate of Designation, which was initially entered into in March 2006. The amendment (a) increased the dividend yield from 6.5% to 12.0% per annum, effective January 1, 2009, (b) established a new conversion commencement date on the outstanding Class A Preferred Units of April 1, 2009, (c) established Sunlight Capital s new conversion option price of $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of our common units, and (d) established a new price for our call redemption right of $27.25. In addition, the amendment required that we issue Sunlight Capital $15.0 million of our 8.125% senior unsecured notes due 2015 (see Senior Notes) to redeem 10,000 Class A Preferred Units. The amendment of the preferred units certificate of designation also required redemption of 15,000 of the Class A Preferred Units for cash in future periods. As such, we reclassified $15.0 million of the $20.0 million of Class A Preferred Units outstanding at March 31, 2009 from Class A Preferred Limited Partner equity within partners capital to preferred unit redemption obligation on our consolidated balance sheet. In April 2009, we and Sunlight Capital agreed that we would convert 5,000 of the Class A Preferred Units into our common units (see Subsequent Events). We will reclassify $5.0 million of the Class A Preferred Units from Class A Preferred Limited Partner equity to common limited partner equity within partners capital when these preferred units are converted to common equity.

Subsequent Events

On May 5, 2009, we redeemed the remaining 5,000 of the Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $5.0 million, pursuant to the terms of the amended preferred units certificate of designation (see Preferred Units Class A Preferred Units). Additionally on May 5, 2009, we paid Sunlight a preferred dividend of $0.2 million, representing the quarterly dividend on the 5,000 Class A Preferred Units held by Sunlight prior to our redemption.

On April 7, 2009, we entered into an agreement with Spectra Energy Partners OLP, LP (NYSE: SEP) (Spectra) related to the sale of our NOARK gas gathering and interstate pipeline system, including Ozark Gas Transmission, LLC and Ozark Gas Gathering, LLC, for $300.0 million cash. The purchase price will be subject to an adjustment based on the working capital of the NOARK system during the periods between the signing date and closing dates. We will account for the sale of the NOARK system assets as discontinued operations within our consolidated financial statements in the future. The transaction closed on May 4, 2009 and we used the net proceeds from the transaction to reduce borrowings under our senior secured term loan and credit facility (see Term Loan and Credit Facility).

On April 1, 2009, we redeemed 10,000 of the Class A Preferred Units held by Sunlight Capital for cash at the liquidation value of $1,000 per unit, or $10.0 million, pursuant to the terms of the amended preferred units certificate of designation (see Preferred Units Class A Preferred Units). Additionally on April 1, 2009, we paid Sunlight a preferred dividend of $0.3 million, representing the quarterly dividend on the 10,000 preferred units held by Sunlight prior to our redemption. On April 13, 2009, Sunlight exercised its right to convert 5,000 Class A Preferred Units into 1,465,653 common limited partner units, which was based on 95% of the market value of our closing common unit price for the 10 business days prior to and including March 31, 2009.

Contractual Revenue Arrangements

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

- the volumes of natural gas we gather, transport and process which, in turn, depend 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; and

- the transportation and processing fees we receive which, in turn, depend upon the price of the natural gas and NGLs we transport and process, which itself is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States.

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In our Appalachian region, substantially all of the natural gas we transport is for Atlas Energy under percentage-of-proceeds (POP) contracts, as described below, in which we earn a fee equal to a percentage, generally 16%, of the gross sales price for natural gas subject, in most cases, to a minimum of $0.35 to $0.40 per thousand cubic feet, or mcf, depending on the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has exceeded this minimum generally. Our gathering agreements with Atlas Energy will terminate upon the sale of our Appalachia gathering system to Laurel Mountain (see Recent Events). The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our Mid-Continent segment revenue consists of the fees earned from our transmission, 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, or produced NGLs, if any, off of delivery points on our systems. Under other agreements, we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. Our revenue is a function of the volume of natural gas that we gather and process and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value; we own a percentage of that commodity and are directly subject to its market value.

Keep-Whole Contracts. These contracts require us, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, we bear the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas. However, because the natural gas purchases contracted under keep-whole agreements are generally low in liquids content and 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. Therefore, the processing margin risk associated with a portion of our keep-whole contracts is minimized.

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 for natural gas transportation and 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, flexibility, 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 POP 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. The number of active oil and gas rigs has increased in recent years, mainly due to recent significant increases in natural gas prices, which could result in sustained increases in drilling activity during the current and future periods. However, energy market uncertainty could negatively impact North American drilling activity in the short term. Lower drilling levels 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. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based on estimated unhedged market prices of $0.70 per gallon, $3.98 per mmbtu and $55.22 per barrel for NGLs, natural gas and condensate, respectively, would change our gross margin for the twelve-month period ending March 31, 2010 by approximately $29.6 million.

Currently, there is an unprecedented 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,	
	2009	**2008**
Operating data[(1)]:		
Appalachia:		
Average throughput volumes (mcfd)	98,529	75,632
Mid-Continent:		
Velma system:		
Gathered gas volume (mcfd)	65,955	62,400
Processed gas volume (mcfd)	63,875	59,867
Residue gas volume (mcfd)	50,173	47,138
NGL volume (bpd)	7,035	6,688
Condensate volume (bpd)	345	254
Elk City/Sweetwater system:		
Gathered gas volume (mcfd)	253,878	305,377
Processed gas volume (mcfd)	253,918	236,403
Residue gas volume (mcfd)	232,038	213,130
NGL volume (bpd)	11,719	10,677
Condensate volume (bpd)	529	363
Chaney Dell system:		
Gathered gas volume (mcfd)	303,022	251,487
Processed gas volume (mcfd)	227,855	247,861
Residue gas volume (mcfd)	255,976	220,194
NGL volume (bpd)	15,531	12,401
Condensate volume (bpd)	927	707
Midkiff/Benedum system:		
Gathered gas volume (mcfd)	153,978	142,542
Processed gas volume (mcfd)	146,055	136,654
Residue gas volume (mcfd)	105,238	96,612
NGL volume (bpd)	22,650	20,349
Condensate volume (bpd)	789	720
NOARK system:		
Average Ozark Gas Transmission throughput volume (mcfd)	482,471	390,293

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

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008

Revenue. Natural gas and liquids revenue was $158.6 million for the three months ended March 31, 2009, a decrease of $207.5 million from $366.1 million for the comparable prior year period. The decline was primarily attributable to decreases in production revenue from the Chaney Dell system of $69.8 million, the Midkiff/Benedum system of $55.5 million, the Elk City/Sweetwater system of $43.0 million and the Velma system of $35.6 million due to significantly lower average commodity prices in comparison to the prior year comparable period, partially offset by an overall increase in processing volumes and plant production efficiency. Processed natural gas volume on the Elk City/Sweetwater system averaged 253.9 MMcfd for the three months ended March 31, 2009, an increase of 7.4% from the comparable prior year period. NGL production volume for the Elk City/Sweetwater system was 11,719 bpd, an increase of 9.8% from the comparable prior year period, as production efficiency of the processing plants increased. The Midkiff/Benedum system had processed natural gas volume of 146.1 MMcfd for the three months ended March 31, 2009, an increase of 6.9% compared to 136.7 MMcfd for the comparable prior year period. NGL production volume for the Midkiff/Benedum system was 22,650 bpd, an increase of 11.3% from the comparable prior year period, as production efficiency of the processing plants increased. Processed natural gas volume averaged 63.9 MMcfd on the Velma system for the three months ended March 31, 2009, an increase of 6.7% from the comparable prior year period. Processed natural gas volume on the Chaney Dell system was 227.9 MMcfd for the three months ended March 31, 2009, a decrease of 8.1% compared to 247.9 MMcfd for the comparable prior year period. However, the Chaney Dell system s NGL production volume increased 25.2% from the comparable prior year period to 15,531 bpd for the three months ended March 31, 2009, representing an increase in production efficiency. 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 Note 9 to the consolidated financial statements in Item 1, Financial Statements .

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Transportation, compression and other fee revenue increased to $26.5 million for the three months ended March 31, 2009 compared with $24.0 million for the comparable prior year period. This $2.5 million increase was primarily due to a $2.7 million increase from the NOARK system and a $1.0 million increase from the Appalachia system due primarily to higher throughput volume, partially offset by $1.2 million decrease of other fee revenue on our other systems. For the NOARK system, average Ozark Gas Transmission volume was 482.5 MMcfd for the three months ended March 31, 2009, an increase of 23.6% from the prior year comparable period due to an increase in throughput capacity to 500.0 MMcfd during the fourth quarter 2008 and higher customer demand. The Appalachia system s average throughput volume was 98.5 MMcfd for the three months ended March 31, 2009 as compared with 75.6 MMcfd for the comparable prior year period, an increase of 22.9 MMcfd or 30.3%. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system.

Other income (loss) net, including the impact of certain gains and losses recognized on derivatives, was income of $5.1 million for the three months ended March 31, 2009, which represents a favorable movement of $91.9 million from the comparable prior year period loss of $86.8 million. This favorable movement was due primarily to a $42.7 million favorable movement in non-cash mark-to-market adjustments on derivatives, a favorable movement of $39.3 million related to cash settlements on derivatives that were not designated as hedges and a non-cash derivative gain of $12.1 million related to the early termination of a portion of our derivative contracts during 2008, partially offset by a net cash loss of $5.0 million related to the early termination of a portion of these derivative contracts (see Note 9 to the consolidated financial statements in Item 1, Financial Statements). The $42.7 million favorable movement in non-cash mark-to-market adjustments on derivatives was due principally to a decrease in forward crude oil market prices from December 31, 2008 to March 31, 2009 and their favorable mark-to-market impact on certain non-hedge derivative contracts we have for production volumes in future periods. For example, average forward crude oil prices, which are the basis for adjusting the fair value of our crude oil derivative contracts, at March 31, 2009 were $54.05 per barrel, a decrease of $2.89 per barrel from average forward crude oil market prices at December 31, 2008 of $56.94 per barrel. 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 Discussion About Market Risk .

Costs and Expenses. Natural gas and liquids cost of goods sold of $138.1 million for the three months ended March 31, 2009 represented a decrease of $138.6 million from the prior year comparable period due primarily to a significant decrease in average commodity prices in comparison to the prior year period, partially offset by higher processing volumes. Plant operating expenses of $13.8 million for the three months ended March 31, 2009 represented a decrease of $1.1 million from the prior year comparable period due to a $1.4 million decrease associated with the Midkiff/Benedum system resulting from lower operating and maintenance costs. Transportation and compression expenses increased $1.0 million to $4.8 million for the three months ended March 31, 2009 due to an increase in Appalachia system operating and maintenance costs as a result of increased capacity and additional well connections in comparison to the prior year period.

General and administrative expense, including amounts reimbursed to affiliates, increased $5.5 million to $11.0 million for the three months ended March 31, 2009 compared with $5.5 million for the prior year comparable period. The increase was primarily related to $2.8 million of non-recurring severance and other related costs incurred during the first quarter 2009 for the termination of certain positions within our Mid-Continent segment and a $2.8 million non-cash compensation net gain recognized during the first quarter 2008 principally associated with the vesting of certain common unit awards that were based on the financial performance of certain assets during 2008. A portion of these common unit awards were issued during the first quarter 2009 with the remainder to be issued during the second quarter 2009. As of December 31, 2008, we recognized the compensation expense associated with these awards in full as we determined the ultimate amount to be issued as of that date (see Note 13 to the consolidated financial statements in Item 1, Financial Statements).

Depreciation and amortization increased to $24.7 million for the three months ended March 31, 2009 compared with $21.8 million for the three months ended March 31, 2008 due primarily to depreciation associated with our expansion capital expenditures incurred subsequent to March 31, 2008.

Interest expense increased to $21.1 million for the three months ended March 31, 2009 as compared with $20.4 million for the comparable prior year period. This $0.7 million increase was primarily due to a $4.9 million increase in interest expense related to our additional senior notes issued during June 2008 (see Senior Notes), partially offset by a $4.9 million decrease in interest expense associated with our senior secured term loan primarily due to the repayment of $122.8 million of indebtedness during June 2008 (see Term Loan and Credit Facility) and lower unhedged interest rates (see Note 9 to the consolidated financial statements in Item 1, Financial Statements).

Asset impairment of $4.0 million for the three months ended March 31, 2008 consisted of a write-off of costs related to a pipeline expansion project. The write-off of costs incurred consisted of a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

Loss attributable to non-controlling interests decreased $1.6 million to a net income reduction of $0.5 million for the three months ended March 31, 2009 compared with $2.1 million for the comparable prior year period. This decrease was primarily due to lower net income for the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to effect our acquisition of control of the respective systems. The income attributable to non-controlling interests represents Anadarko 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 additional borrowings as they become due or by the issuance of additional limited partner units or asset sales.

At March 31, 2009, we had $324.0 million outstanding under our $380.0 million senior secured credit facility and $5.4 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $50.6 million of remaining committed capacity under the credit facility, subject to covenant limitations (see Term Loan and Credit Facility). We were in compliance with the credit facility s covenants at March 31, 2009. At March 31, 2009, we had a working capital deficit of $131.1 million compared with a working capital deficit of $48.8 million at December 31, 2008. This decrease in working capital was primarily due to a $51.3 million decrease in the current portion of net derivative assets and a $31.1 million decrease in accounts receivable. 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.

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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 significantly. 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.

Cash Flows Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008

Net cash provided by operating activities of $64.4 million for the three months ended March 31, 2009 represented an increase of $9.5 million from $54.9 million for the prior year comparable period. The increase was derived principally by a $16.8 million increase in cash flows from working capital changes, partially offset by a $7.3 million unfavorable movement in net loss excluding non-cash charges. The decrease in net loss excluding non-cash charges was principally due to lower average commodity prices when compared with the prior year comparable period, partially offset by higher processing volumes. Non-cash charges which impacted net loss excluding non-cash charges include a $30.9 million decrease in non-cash derivative losses and a $4.0 million decrease from asset impairment loss, partially offset by a $2.8 million increase in depreciation and amortization expense and a $2.7 million increase in non-cash compensation expense. The movement in non-cash derivative losses resulted from decreases in commodity prices during the three months ended March 31, 2009 and their favorable impact on the fair value of derivative contracts we have for future periods. The increase in depreciation and amortization principally resulted from depreciation associated with our expansion capital expenditures incurred subsequent to March 31, 2008. The increase in non-cash compensation expense was principally attributable to a $2.8 million non-cash compensation net gain in the first quarter 2008 principally associated with the vesting of certain common unit awards based on the financial performance of certain assets during 2008. The first quarter 2008 gain was attributable to a mark-to-market adjustment for these common unit awards as a the result of a decrease in our common unit market price at March 31, 2008 when compared with the December 31, 2007 price, which was utilized in the estimate of the non-cash compensation expense for these awards.

Net cash used in investing activities was $73.0 million for the three months ended March 31, 2009, a decrease of $10.0 million from $83.0 million for the prior year comparable period. This decrease was principally due to an $11.2 million decrease in capital expenditures, partially offset by a prior year period receipt of $1.3 million in connection with a post-closing purchase price adjustment of our 2007 acquisition of the Chaney Dell and Midkiff/Benedum systems. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities was $9.0 million for the three months ended March 31, 2009, a decrease of $9.7 million from $18.7 million for the comparable prior year period. This decrease was principally due to a $38.0 million net decrease in borrowings under our revolving credit facility, partially offset by a $23.0 million decrease in cash distributions to common limited partners and the general partner and a $5.0 million increase in net proceeds from the issuance of preferred units as a result of our issuance of 5,000 additional Class B Preferred Units to AHD.

Capital Requirements

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

- maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and expansion capital expenditures to acquire complementary assets and to expand the capacity of our existing operations.

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

	Three Months Ended March 31,	
	2009	2008
Maintenance capital expenditures	$ 695	$ 1,619
Expansion capital expenditures	72,218	82,450
Total	$ 72,913	$ 84,069

Expansion capital expenditures decreased to $72.2 million for the three months ended March 31, 2009 compared with $82.5 million for the prior year first quarter due principally to construction of a 60MMcfd expansion of our Sweetwater processing plant and the acquisition of a gathering system located in Tennessee during the first quarter of 2008, partially offset by continued expansion of our gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. The decrease in maintenance capital expenditures for the three months ended March 31, 2009 when compared with the comparable prior year period was due to fluctuations in the timing of our scheduled maintenance activity. As of March 31, 2009, we are committed to expend approximately $56.7 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash to our common unitholders and our general partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all 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% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. During July 2007, our general partner, holder of all of our incentive distribution rights, agreed to allocate up to $5.0 million of incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems. Our general partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the general partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter.

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Off Balance Sheet Arrangements

As of March 31, 2009, our off balance sheet arrangements are limited to our letters of credit outstanding of $5.4 million and our commitments to expend approximately $56.7 million on capital projects.

Common Equity Offerings

In June 2008, we sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also in June 2008, we sold 1,112,000 common units to Atlas America and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. We also received a capital contribution from AHD of $5.4 million for AHD to maintain its 2.0% general partner interest in us. We utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements.

Cumulative Preferred Units

Class A Preferred Units

At March 31, 2009, we had 20,000 $1,000 par value 12.0% cumulative convertible Class A preferred units of limited partner interests (the Class A Preferred Units) outstanding that are held by Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates. In January 2009, we and Sunlight Capital agreed to amend certain terms of the preferred units certificate of designation, which was initially entered into in March 2006. The amendment (a) increased the dividend yield from 6.5% to 12.0% per annum, effective January 1, 2009, (b) established a new conversion commencement date on the outstanding Class A Preferred Units of April 1, 2009, (c) established Sunlight Capital s new conversion option price of $22.00, enabling the Class A Preferred Units to be converted at the lesser of $22.00 or 95% of the market value of our common units, and (d) established a new price for our call redemption right of $27.25.

The amendment to the preferred units certificate of designation also required that we issue Sunlight Capital $15.0 million of our 8.125% senior unsecured notes due 2015 (see Senior Notes) to redeem 10,000 Class A Preferred Units. Our management estimated that the fair value of the $15.0 million 8.125% senior unsecured notes issued to redeem the Class A Preferred Units was approximately $10.0 million at the date of redemption based upon the market price of the publicly-traded senior notes. As such, we recorded the redemption by recognizing a $10.0 million reduction of Class A Preferred equity within Partners Capital, $15.0 million of additional long-term debt for the face value of the senior unsecured notes issued, and a $5.0 million discount on the issuance of the senior unsecured notes that will be presented as a reduction of long-term debt on our consolidated balance sheet. The discount recognized upon issuance of the senior unsecured notes will be amortized to interest expense in our consolidated statements of operations over the term of the notes based upon the effective interest rate method.

The amendment to the preferred units certificate of designation also required that (a) we redeem 10,000 of the Class A Preferred Units for cash at the liquidation value on April 1, 2009 and (b) that if Sunlight Capital made a conversion request of the remaining 10,000 Class A Preferred Units between April 1, 2009 and June 1, 2009, we have the option of redeeming the Class A Preferred Units for cash at the stipulated liquidation value or converting the Class A Preferred Units into our common limited partner units at the stipulated conversion price. If Sunlight Capital made a conversion request subsequent to June 1, 2009, 5,000 of the 10,000 Class A Preferred Units are required to be redeemed in cash, while we have the option of redeeming the remaining 5,000 Class A Preferred Units in cash or converting the preferred units into our common limited partner units.

We follow the provisions of Statement of Financial Accounting Standards (SFAS) No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity (SFAS No. 150). SFAS No. 150 states that financial instruments which are mandatorily redeemable shall be classified as a liability unless the redemption is required to occur only upon the liquidation or termination of the reporting entity. A financial instrument issued in the form of units is mandatorily redeemable if it embodies an unconditional obligation requiring the issuer to redeem the instrument by transferring assets at a specified or determinable date. The amendment of the preferred units certificate of designation required redemption of 15,000 of the Class A Preferred Units for cash in future periods. As such, we reclassified $15.0 million of the $20.0 million of Class A Preferred Units outstanding at March 31, 2009 from Class A Preferred Limited Partner equity within partners capital to preferred unit redemption obligation on our consolidated balance sheet. In addition, in April 2009, we and Sunlight Capital agreed that we would convert 5,000 of the Class A Preferred Units into our common units. We will reclassify $5.0 million of the Class A Preferred Units from Class A Preferred Limited Partner equity to common limited partner equity within partners capital when these preferred units are converted to common equity.

Class B Preferred Units

In December 2008, we sold 10,000 12.0% cumulative convertible Class B preferred units of limited partner interests (the Class B Preferred Units) to AHD for cash consideration of $1,000 per Class B Preferred Unit (the Face Value) pursuant to a certificate of designation (the Class B Preferred Units Certificate of Designation). On March 30, 2009, AHD, pursuant to its right within the Class B Preferred Unit Purchase Agreement, purchased an additional 5,000 Class B Preferred Units at Face Value. We used the proceeds from the sale of the Class B Preferred Units for general partnership purposes. The Class B Preferred Units receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for our common units. The record date of determination for holders entitled to receive distributions of the Class B Preferred Units will be the same as the record date of determination for common unit holders entitled to receive quarterly distributions. Additionally, on March 30, 2009, we and AHD agreed to amend the terms of the Class B Preferred Units Certificate of Designation to remove the conversion feature, thus the Class B Preferred Units are not convertible into our common units. The amended Class B Preferred Units Certificate of Designation also gives us the right at any time to redeem some or all of the outstanding Class B Preferred Units for cash at an amount equal to the Class B Preferred Unit Liquidation Value being redeemed, provided that such redemption must be exercised for no less than the lesser of a) 2,500 Class B Preferred Units or b) the number of remaining outstanding Class B Preferred Units.

The cumulative sale of the Class B Preferred Units to AHD is exempt from the registration requirements of the Securities Act of 1933. Dividends paid on the Class B Preferred Units and the premium paid upon the redemption of the Class B Preferred Units, if any, will be recognized as a reduction of our net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. The Class B Preferred Units are reflected on our consolidated balance sheet as Class B preferred equity within partners capital.

Term Loan and Credit Facility

At March 31, 2009, 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 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, 2009 was 2.8%, and the weighted average interest rate on the outstanding term loan borrowings at March 31, 2009 was 3.3%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $5.4 million was outstanding at March 31, 2009. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet.

In June 2008, we entered into an amendment to our revolving credit facility and term loan agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to our early termination of certain derivative contracts (see Note 9 to the consolidated financial statements in Item 1, Financial Statements) in calculating our Consolidated EBITDA. Pursuant to this amendment, in June 2008, we repaid $122.8 million of our outstanding term loan and repaid $120.0 million of outstanding borrowings under the credit facility with proceeds from our issuance of $250.0 million of 10-year, 8.75% senior unsecured notes (see Senior Notes). Additionally, pursuant to this amendment, in June 2008 our lenders increased their commitments for our revolving credit facility by $80.0 million to $380.0 million.

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 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 in compliance with these covenants as of March 31, 2009. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt or equity issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with entering into the credit facility, we agreed to remit an underwriting fee to the lead underwriting bank based upon the aggregate principal amount of the term loan outstanding, subject to adjustments as stated in the agreement.

The events which constitute an event of default for our credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, 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 a ratio of funded debt (as defined in the credit facility) to Consolidated EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.75 to 1.0. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of March 31, 2009, our ratio of funded debt to EBITDA was 4.9 to 1.0 and our interest coverage ratio was 4.0 to 1.0.

We are 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.

Senior Notes

At March 31, 2009, we had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $270.5 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 $0.6 million of unamortized premium received as of March 31, 2009. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time 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.

In January 2009, we issued Sunlight Capital $15.0 million of our 8.125% Senior Notes to redeem 10,000 Class A Preferred Units (see Preferred Units Class A Preferred Units). Our management estimated that the fair value of the $15.0 million 8.125% Senior Notes issued was approximately $10.0 million at the date of issuance based upon the market price of the publicly-traded Senior Notes. As such, we recognized a $5.0 million discount on the issuance of the Senior Notes, which is presented as a reduction of long-term debt on our consolidated balance sheet. The discount recognized upon issuance of the Senior Notes will be amortized to interest expense in our consolidated statements of operations over the term of the 8.125% Senior Notes based upon the effective interest rate method.

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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 its assets. We are in compliance with these covenants as of March 31, 2009.

In connection with the issuance of the 8.75% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If we did not meet the aforementioned deadline, the 8.75% Senior Notes would have been subject to additional interest, up to 1% per annum, until such time that we had caused the exchange offer to be consummated. On November 21, 2008, we filed an exchange offer registration statement for the 8.75% Senior Notes with the Securities and Exchange Commission, which was declared effective on December 16, 2008. The exchange offer was consummated on January 21, 2009, thereby fulfilling all of the requirements of the 8.75% Senior Notes registration rights agreement by the specified dates.

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, 2008, and there have been no material changes to these policies through March 31, 2009.

Fair Value of Financial Instruments

We apply the provisions of SFAS No. 157, Fair Value Instruments (SFAS No. 157), to our financial statements. SFAS No. 157 establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. SFAS No. 157 (1) creates a single definition of fair value, (2) establishes a hierarchy for measuring fair value, and (3) expands disclosure requirements about items measured at fair value. SFAS No. 157 does not change existing accounting rules governing what can or what must be recognized and reported at fair value in our financial statements, or disclosed at fair value in our notes to the financial statements. As a result, we will not be required to recognize any new assets or liabilities at fair value.

SFAS No. 157 s 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.

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

Level 3 Unobservable inputs that reflect the entity s own assumptions about the 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 the fair value methodology outlined in SFAS No. 157 to value the assets and liabilities for our respective outstanding derivative contracts (see Note 10 to the consolidated financial statements in Item 1, Financial Statements). All of our derivative contracts are defined as Level 2, with the exception of our NGL fixed price swaps and crude oil 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 natural gas, crude oil, and propane prices, and therefore are defined as Level 3. Valuations for our crude oil options (including those associated with NGL sales) are based on forward price curves developed by the related financial institution based upon current quoted prices for crude oil futures, and therefore are defined as Level 3.

Recently Adopted Accounting Standards

In June 2008, the Financial Accounting Standards Board (FASB) issued the Emerging Issues Task Force s (EITF) Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 applies to the calculation of earnings per share (EPS) described in paragraphs 60 and 61 of FASB Statement No. 128, Earnings per Share for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS pursuant to the two-class method. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption was prohibited. We adopted the requirements of FSP EITF 03-6-1 on January 1, 2009 and its adoption did not have a material impact on our financial position and results of operations (see Net Income (Loss) Per Common Unit in Note 2 to the consolidated financial statements in Item 1, Financial Statements). Prior-period net loss per common limited partner unit data presented has been adjusted retrospectively to conform to the provisions of FSP EITF 03-6-1.

In April 2008, the FASB issued Staff Position No. 142-3, Determination of Useful Life of Intangible Assets (FSP FAS 142-3). FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, Goodwill and Other Intangible Assets (SFAS 142). The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No 141(R), Business Combinations (SFAS No. 141(R)), and other U.S. Generally Accepted Accounting Principles. We adopted the requirements of FSP FAS 142-3 on January 1, 2009 and its adoption did not have a material impact on our financial position and results of operations.

In March 2008, the FASB ratified the EITF consensus on EITF Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF No. 07-4), an update of EITF No. 03-6, Participating Securities and the Two-Class Method Under FASB Statement No. 128 (EITF No. 03-6). EITF 07-4 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. EITF 07-4 also considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount

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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. The adoption of EITF No. 07-4 on January 1, 2009 impacted our presentation of net income (loss) per common limited partner unit as we previously presented net income (loss) per common limited partner unit as though all earnings were distributed each quarterly period (see Net Income (Loss) Per Common Unit in Note 2 to the consolidated financial statements in Item 1, Financial Statements). Under the guidance of EITF 07-4, our management believes that the partnership agreement contractually limits cash distributions to available cash and, therefore, undistributed earnings will no longer be allocated to the incentive distribution rights.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 161 amends the requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to require enhanced disclosure about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. We adopted the requirements of SFAS No. 161 on January 1, 2009 and it did not have a material impact on our financial position or results of operations (see Note 9 to the consolidated financial statements in Item 1, Financial Statements).

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidated Financial Statements-an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 amends ARB No. 51 to establish accounting and reporting standards for the non-controlling interest (minority interest) in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 also requires consolidated net income to be reported and disclosed on the face of the consolidated statement of operations at amounts that include the amounts attributable to both the parent and the non-controlling interest. Additionally, SFAS No. 160 establishes a single method of accounting for changes in a parent s ownership interest in a subsidiary that does not result in deconsolidation and that the parent recognize a gain or loss in net income when a subsidiary is deconsolidated. We adopted the requirements of SFAS No. 160 on January 1, 2009 and adjusted our presentation of our financial position and results of operations. Prior period financial position and results of operations have been adjusted retrospectively to conform to the provisions of SFAS No. 160.

In December 2007, the FASB issued SFAS No 141(R), Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) replaces SFAS No. 141, Business Combinations (SFAS No. 141), however retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) requires an acquirer to recognize the assets acquired, liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, at their fair values as of that date, with specified limited exceptions. Changes subsequent to that date are to be recognized in earnings, not goodwill. Additionally, SFAS No. 141 (R) requires costs incurred in connection with an acquisition be expensed as incurred. Restructuring costs, if any, are to be recognized separately from the acquisition. The acquirer in a business combination achieved in stages must also recognize the identifiable assets and liabilities, as well as the non-controlling interests in the acquiree, at the full amounts of their fair values. We adopted the requirements of SFAS No. 141(R) on January 1, 2009 and it did not have a material impact on our financial position and results of operations.

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 periodic use of derivative instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on March 31, 2009. 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 who also participate in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At March 31, 2009, we had a $380.0 million senior secured revolving credit facility ($324.0 million outstanding). We also had $707.2 million outstanding under our senior secured term loan at March 31, 2009. The weighted average interest rate for the revolving credit facility borrowings was 2.8% at March 31, 2009, and the weighted average interest rate for the term loan borrowings was 3.3% at March 31, 2009.

At March 31, 2009, we have interest rate derivative contracts having aggregate notional principal amounts of $450.0 million. Under the terms of these agreements, we will pay weighted average interest rates of 3.02%, 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. These derivatives effectively convert $450.0 million of our floating rate debt under the term loan and revolving credit facility to fixed-rate debt. The interest rate swap agreements are effective as of March 31, 2009 and expire during periods ranging from January 30, 2010 through April 30, 2010.

Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by $5.8 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based on estimated unhedged market prices of $0.70 per gallon, $3.98 per mmbtu and $55.22 per barrel for NGLs, natural gas and condensate, respectively, would change our gross margin for the twelve-month period ending March 31, 2010 by approximately $29.6 million.

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price and interest rate 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. We also enter into financial swap instruments to hedge certain portions of our 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 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 purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period.

We apply the provisions of SFAS No. 133 to our derivative instruments. We formally document all relationships between hedging instruments and the items being hedged, including our risk management objective and strategy for undertaking the hedging transactions. This includes matching derivative contracts to the forecasted transactions. Under SFAS No. 133, we can assess, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying item being hedged, we will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by us through the utilization of market data, will be recognized within other income (loss) in our consolidated statements of operations. For derivatives previously qualifying as hedges, we recognized the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss) and reclassified the portion relating to commodity derivatives to natural gas and liquids revenue and the portion relating to interest rate derivatives to interest expense within our consolidated statements of operations as the underlying transactions were settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within other income (loss) in our consolidated statements of operations as they occur.

Beginning July 1, 2008, we discontinued hedge accounting for our existing commodity derivatives which were qualified as hedges under SFAS No. 133. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss) in our 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 our consolidated balance sheet, will be reclassified to our consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings.

During the three months ended March 31, 2009 and year ended December 31, 2008, we made net payments of $5.0 million and $274.0 million, respectively, related to the early termination of derivative contracts. Substantially all of these derivative contracts were put into place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. During the three months ended March 31, 2009 and 2008, we recognized the following derivative activity related to the termination of these derivative instruments within our consolidated statements of operations (amounts in thousands):

	Early Termination of Derivative Contracts for the Three Months Ended March 31,	
	2009	**2008**
Net cash derivative expense included within other income (loss), net	$ (5,000)	$
Net cash derivative expense included within natural gas and liquids revenue		
Net non-cash derivative income included within other income (loss), net	12,103	
Net non-cash derivative expense included within natural gas and liquids	(21,944)	

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In addition, at March 31, 2009, $25.3 million will be reclassified from accumulated other comprehensive loss within partner s capital on our consolidated balance sheet and recognized as non-cash derivative expense during the period beginning on April 1, 2009 and ending on December 31, 2009, the remaining period for which the derivatives were originally scheduled to be settled, as a result of the early termination of certain derivatives that were classified as cash flow hedges in accordance with SFAS No. 133 at the date of termination.

The following table summarizes our derivative activity for the periods indicated (amounts in thousands):

	Three Months Ended March 31,	
	2009	2008
Loss from cash and non-cash settlement of qualifying hedge instruments(1)	$ (20,175)	$ (17,643)
Loss from change in market value of non-qualifying derivatives(2)	(44,990)	(71,196)
Gain (loss) from change in market value of ineffective portion of qualifying derivatives(2)	10,813	(5,660)
Gain (loss) from cash and non-cash settlement of non-qualifying derivatives(2)	34,495	(11,925)
Loss from cash settlement of interest rate derivatives(3)	(2,893)	

(1) Included within natural gas and liquids revenue on our consolidated statements of operations.

(2) Included within other income (loss), net on our consolidated statements of operations.

(3) Included within interest expense on our consolidated statements of operations.

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

	March 31, 2009			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments under SFAS No. 133:				
Interest rate contracts	Current portion of derivative asset	$	Current portion of derivative liability	$ (9,685)
Interest rate contracts	Long-term derivative asset		Long-term derivative liability	(442)
Derivatives not designated as hedging instruments under SFAS No. 133:				
Commodity contracts	Current portion of derivative liability	3,977	Current portion of derivative liability	(60,991)
Commodity contracts	Long-term derivative liability	2,380	Long-term derivative liability	(25,147)
		$ 6,357		$ (96,265)

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The following table summarizes the gross effect of derivative instruments on our consolidated statement of operations for the period indicated (amounts in thousands):

	March 31, 2009			
	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	**Location of Gain(Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**	**Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)**	**Location of Gain (Loss) Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)**
Derivatives in SFAS No. 133 Cash Flow Hedging Relationships:				
Interest rate contracts	$ (2,893)	Interest expense	$	N/A
Derivatives not designated as hedging instruments under SFAS No. 133:				
Commodity contracts[(1)]	$ (15,970)	Natural gas and liquids revenue	$ (9,527)	Other income (loss), net
Commodity contracts[(2)]			39,820	Other income (loss), net
	$ (18,863)		$ 30,293	

(1) Hedges previously designated as cash flow hedges

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

As of March 31, 2009, we had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Term	Notional Amount	Type		Contract Period Ended December 31,	Fair Value Liability[(1)] (in thousands)
January 2008 - January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	2009	$ (3,374)
				2010	(304)
					$ (3,678)
April 2008 - April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2009	$ (4,715)
				2010	(1,734)
					$ (6,449)

Natural Gas Liquids Sales   Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Asset(2) (in thousands)
2009	13,230,000	$ 0.745	$ 1,579

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Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)(1) (in thousands)	Option Type
2009	152,100	13,542,984	$ 111.53	$ (11,171)	Puts sold(4)
2009	152,100	13,542,984	$ 157.82		Calls purchased(4)
2009	1,588,500	88,643,058	$ 84.69	(2,019)	Calls sold
2010	3,127,500	213,088,050	$ 86.20	(13,035)	Calls sold
2010	714,000	45,415,440	$ 132.17	638	Calls purchased(4)
2011	606,000	33,145,560	$ 100.70	(3,071)	Calls sold
2011	252,000	13,547,520	$ 133.16	665	Calls purchased(4)
2012	450,000	25,893,000	$ 102.71	(2,822)	Calls sold
2012	180,000	9,676,800	$ 134.27	657	Calls purchased(4)
				$ (30,158)	

Natural Gas Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Asset (3) (in thousands)
2009	360,000	$ 8.000	$ 1,337

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Asset (3) (in thousands)
2009	3,690,000	$ (0.558)	$ 673
2010	2,220,000	$ (0.575)	301
			$ 974

Natural Gas Purchases Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(5)	Average Fixed Price (per mmbtu)(5)	Fair Value Liability(3) (in thousands)
2009	7,740,000	$ 8.687	$ (34,069)
2010	4,380,000	$ 8.635	(12,806)
			$ (46,875)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)[5]	Average Fixed Price (per mmbtu)[5]	Fair Value Liability[3] (in thousands)
2009	11,070,000	$ (0.659)	$ (2,837)
2010	6,600,000	$ (0.560)	(1,783)
			$ (4,620)

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Ethane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Asset(1) (in thousands)	Option Type
2009	630,000	$ 0.340	$ 12	Puts purchased

Isobutane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(1) (in thousands)	Option Type
2009	126,000	$ 0.589	$ (10)	Puts purchased

Normal Butane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(1) (in thousands)	Option Type
2009	126,000	$ 0.577	$ (10)	Puts purchased

Natural Gasoline Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Crude Strike Price (per gallon)	Fair Value Liability(1) (in thousands)	Option Type
2009	126,000	$ 0.762	$ (10) 5	Puts purchased

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Asset(3) (in thousands)
2009	24,000	$ 62.700	$ 206

Crude Oil Sales Options

Production Period Ended December 31,	Volumes	Average Strike Price	Fair Value Liability(1)	Option Type

	(barrels)	(per barrel)	(in thousands)	
2009	229,500	$ 84.802	$ (314)	Calls sold
2010	234,000	$ 88.088	(912)	Calls sold
2011	72,000	$ 93.109	(502)	Calls sold
2012	48,000	$ 90.314	(478)	Calls sold
			$ (2,206)	
Total net liability			$ (89,908)	

(1) Fair value based on independent, third-party statements, supported by observable levels at which transactions are executed in the marketplace.

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(2) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas, light crude and propane prices.

(3) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

(4) Puts sold and calls purchased for 2009 represent costless collars entered into by us as offsetting positions for the calls sold related to ethane and propane production. In addition, calls were purchased for 2010 through 2012 to offset 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.

(5) Mmbtu represents million British Thermal Units.

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.

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 at March 31, 2009, our disclosure controls and procedures were effective at the reasonable assurance level.

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In January 2009, in the matter captioned Elk City Oklahoma Pipeline, L.P. v. Northern Natural Gas Company , (District Court of Tulsa County, Oklahoma), Elk City Oklahoma Pipeline, L.P. (Elk City), a subsidiary of ours, filed a petition against Northern Natural Gas Company (NNG), seeking a declaratory judgment related to the interpretation of a Purchase and Sale Agreement for certain pipeline and assets in Western Oklahoma which was entered into between the two parties on June 12, 2008 (the PSA). In March 2009, NNG filed a petition together with a motion for summary judgment alleging breach of the PSA for Elk City s failure to complete the purchase and seeking specific performance or, alternatively, damages, in the matter captioned Northern Natural Gas Company vs. Elk City Oklahoma Pipeline, L.P. , (District Court of Tulsa County, Oklahoma). Both matters are currently pending. We believe that the claims are without merit and intend to pursue our action and defend against NNG s claims. Additionally, we believe that the ultimate resolution of these matters will not have a material impact on our financial position and results of operations.

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, 2008.

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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[(6)]
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership[(7)]
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership[(11)]
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership[(14)]
3.3	Second Amended and Restated Certificate of Designation for 12% Cumulative Convertible Preferred Units[(5)]
3.4	Amended and Restated Certificate of Designation for 12% Cumulative Convertible Class B Preferred Units[(14)]
4.1	Common unit certificate[(1)]
4.2	8 $^{1}/8$% Senior Notes Indenture dated December 20, 2005[(12)]
4.3	8 $^{3}/4$% Senior Notes Indenture dated June 27, 2008[(9)]
10.1(a)	Revolving Credit and Term Loan Agreement dated July 27, 2007[(4)]
10.1(b)	Amendment No. 1 and Agreement to the Revolving Credit and Term Loan Agreement, dated June 12, 2008[(7)]
10.1(c)	Increase Joinder dated June 27, 2008[(10)]
10.2	Common Unit Purchase Agreement dated June 17, 2008, by and among Atlas Pipeline Partners, L.P., Atlas America, Inc. and Atlas Pipeline Holdings, L.P.[(8)]
10.3	8 $^{3}/4$% Senior Notes Purchase Agreement dated June 24, 2008, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corp., the subsidiary guarantors and Wachovia Capital Markets LLC, as representative of the several initial purchasers[(9)]
10.4	Registration Rights Agreement dated June 27, 2008, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corp., the subsidiary guarantors and Wachovia Capital Markets LLC, as representative of the several initial purchasers[(9)]

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10.5	Class B Preferred Unit Purchase Agreement dated December 30, 2008, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P.[11]
10.6	Registration Rights Agreement dated December 30, 2008, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P. [11]
10.7	Purchase Agreement dated as of January 27, 2009, between Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, Sunlight Capital Partners, LLC, Elliott Associates, L.P. and Elliott International, L.P.[5]
10.8	Purchase Option Agreement between Atlas Pipeline Mid-Continent WestTex, LLC and Pioneer Natural Resources USA, Inc. dated July 27, 2007[4]
10.9	Long-Term Incentive Plan[13]
10.10	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
10.11	Employment agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay
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 29, 2009.

(6) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.

(7) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.

(8) Previously filed as an exhibit to current report on Form 8-K on June 23, 2008.

(9) Previously filed as an exhibit to current report on Form 8-K on June 27, 2008.

(10) Previously filed as an exhibit to current report on Form 8-K on July 3, 2008.

(11) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.

(12) Previously filed as an exhibit to current report on Form 8-K on December 21, 2005.

(13) Previously filed as an exhibit to annual report on Form 10-K for the year ended December 31, 2008.

(14) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.

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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 11, 2009	By: /s/ EUGENE N. DUBAY Chief Executive Officer, President and Managing
	Board Member of the General Partner
Date: May 11, 2009	By: /s/ MATTHEW A. JONES Matthew A. Jones
	Chief Financial Officer of the General Partner
Date: May 11, 2009	By: /s/ SEAN P. MCGRATH Sean P. McGrath
	Chief Accounting Officer of the General Partner