ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 07, 2009

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 June 30, 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 August 5, 2009 was 47,809,425.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO QUARTERLY REPORT

ON FORM 10-Q

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	June 30, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 947	$ 1,445
Accounts receivable affiliates		537
Accounts receivable	77,118	100,000
Current portion of derivative asset	1,815	44,961
Prepaid expenses and other	13,382	10,996
Current assets of discontinued operations		13,441
Total current assets	93,262	171,380
Property, plant and equipment, net	1,726,027	1,781,011
Intangible assets, net	180,869	193,647
Investment in joint venture	133,803	
Long-term portion of derivative asset	1,606	
Other assets, net	34,077	24,993
Long-term assets of discontinued operations		242,165
	$ 2,169,644	$ 2,413,196
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable affiliates	$ 1,643	$
Accounts payable	21,348	66,571
Accrued liabilities	20,570	15,809
Current portion of derivative liability	57,660	60,396
Accrued producer liabilities	47,066	66,846
Current liabilities of discontinued operations		10,572
Total current liabilities	148,287	220,194
Long-term derivative liability	12,748	48,159
Long-term debt, less current portion	1,276,300	1,493,427
Other long-term liability	490	574
Commitments and contingencies		
Partners capital:		
Class A preferred limited partner s interest		27,853
Class B preferred limited partner s interest	14,955	10,007
Common limited partners interests	819,826	735,742
Investment in Class B cumulative preferred member units of Atlas Pipeline Holdings II, LLC (reported as treasury units)	(15,000)	
General partner s interest	16,497	14,521

Accumulated other comprehensive loss	(74,523)	(104,944)
	761,755	683,179
Non-controlling interest	(29,936)	(32,337)
Total partners capital	731,819	650,842
	$ 2,169,644	$ 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 June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Revenue:				
Natural gas and liquids	$ 176,888	$ 430,334	$ 332,038	$ 789,949
Transportation, compression and other fees affiliates	6,429	11,421	16,497	20,580
Transportation, compression and other fees third parties	3,981	5,671	7,855	10,667
Equity income in joint venture	710		710	
Gain on asset sale	109,941		109,941	
Other loss, net	(15,645)	(314,259)	(10,496)	(401,014)
Total revenue and other loss, net	282,304	133,167	456,545	420,182
Costs and expenses:				
Natural gas and liquids	129,676	349,711	264,421	623,537
Plant operating	14,128	14,831	27,951	29,766
Transportation and compression	2,791	2,645	6,122	4,959
General and administrative	6,164	8,168	16,467	12,157
Compensation reimbursement affiliates	375	1,390	750	2,519
Depreciation and amortization	22,999	20,412	45,667	40,459
Interest	26,392	19,814	47,500	40,565
Total costs and expenses	202,525	416,971	408,878	753,962
Income (loss) from continuing operations	79,779	(283,804)	47,667	(333,780)
Discontinued operations:				
Gain on sale of discontinued operations	51,078		51,078	
Income from discontinued operations	2,541	8,245	11,417	14,491
Income from discontinued operations	53,619	8,245	62,495	14,491
Net income (loss)	133,398	(275,559)	110,162	(319,289)
Income attributable to non-controlling interests	(652)	(3,112)	(1,121)	(5,202)
Preferred unit dividends		(650)	(900)	(787)
Preferred unit imputed dividend cost				(505)
Net income (loss) attributable to common limited partners and the general partner	$ 132,746	$ (279,321)	$ 108,141	$ (325,783)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partner interest:				
Continuing operations	$ 77,537	$ (289,855)	$ 44,729	$ (348,363)
Discontinued operations	52,541	8,079	61,239	14,200
	130,078	(281,776)	105,968	(334,163)
General partner interest:				
Continuing operations	1,590	2,289	917	8,089

Discontinued operations	1,078	166	1,256	291
	2,668	2,455	2,173	8,380
Net income (loss) attributable to common limited partners and the general partner:				
Continuing operations	79,127	(287,566)	45,646	(340,274)
Discontinued operations	53,619	8,245	62,495	14,491
	$ 132,746	$ (279,321)	$ 108,141	$ (325,783)
Net income (loss) attributable to common limited partners per unit:				
Basic:				
Continuing operations	$ 1.62	$ (7.34)	$ 0.95	$ (8.88)
Discontinued operations	1.11	0.21	1.31	0.36
	$ 2.73	$ (7.13)	$ 2.26	$ (8.52)
Diluted:				
Continuing operations	$ 1.62	$ (7.34)	$ 0.95	$ (8.88)
Discontinued operations	1.11	0.21	1.31	0.36
	$ 2.73	$ (7.13)	$ 2.26	$ (8.52)
Weighted average common limited partner units outstanding:				
Basic	47,529	39,329	46,755	39,046
Diluted	47,529	39,329	46,755	39,046

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE SIX MONTHS ENDED JUNE 30, 2009

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units			Class A Preferred	Class B Preferred	Common		Accumulated Other	Class B Preferred Units of Atlas Pipeline	Non-	Total
	Class A Preferred	Class B Preferred	Common	Limited Partner	Limited Partner	Limited Partners	General Partner	Comprehensive Income (Loss)	Holdings II, LLC	controlling Interests	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
Redemption of Class A cumulative convertible preferred limited partner units	(25,000)			(25,000)							(25,000)
Conversion of Class A cumulative convertible preferred limited partner units	(5,000)		1, 465,653	(2,528)		2,528					
Issuance of Class B preferred limited partner units		5,000			4,955						4,955
General partner capital contribution							308				308
Distributions to non-controlling interests										1,280	1,280
Unissued common units under incentive plans						259					259
Issuance of common units under incentive plans			383,714								
Distributions paid to common limited partners, the general				(775)	(457)	(24,612)	(505)				(26,349)

partner and preferred limited partners										
Purchase of Class B cumulative preferred member units of unissued Atlas Pipeline Holdings II, LLC (reported as treasury units)								(15,000)		(15,000)
Distribution equivalent rights paid on unissued units under incentive plans					(59)					(59)
Other comprehensive income							30,421			30,421
Net income			450	450	105,968	2,173			1,121	110,162
Balance at June 30, 2009	15,000	47,804,175	$	$ 14,955	$ 819,826	$ 16,497	$ (74,523)	$ (15,000)	$ (29,936)	$ 731,819

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 110,162	$ (319,289)
Less: Income from discontinued operations	62,495	14,491
Net income (loss) from continuing operations	47,667	(333,780)
Adjustments to reconcile net loss from continuing operations to net cash provided by operating activities:		
Depreciation and amortization	45,667	40,459
Non-cash loss on derivative value, net	33,814	201,834
Equity income in joint venture	(710)	
Gain on asset sale	(109,941)	
Distribution received from joint venture	164	
Non-cash compensation expense (income)	259	(1,600)
Amortization of deferred finance costs	4,653	2,608
Net distributions to non-controlling interests	1,280	(5,052)
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable, prepaid expenses and other	20,422	(42,320)
Accounts payable and accrued liabilities	(18,817)	182,176
Accounts payable and accounts receivable affiliates	2,180	(459)
Net cash provided by continuing operations	26,638	43,866
Net cash provided by discontinued operations	16,935	21,851
Net cash provided by operating activities	43,573	65,717
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisition purchase price adjustment		31,429
Capital expenditures	(130,494)	(142,054)
Net proceeds from asset sale	87,795	
Other	(2,346)	342
Net cash used in continuing investing activities	(45,045)	(110,283)
Net cash provided by (used in) discontinued investing activities	290,594	(15,143)
Net cash provided by (used in) investing activities	245,549	(125,426)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from issuance of debt		244,854
Repayment of debt	(247,295)	(122,820)
Borrowings under credit facility	325,000	163,000
Repayments under credit facility	(305,000)	(248,000)
Net proceeds from issuance of Class B preferred limited partner units	4,955	
Net proceeds from issuance of common limited partner units		257,174
Redemption of Class A preferred units	(15,000)	
General partner capital contributions	308	5,452
Purchase of Class B cumulative preferred units of Atlas Pipeline Holdings II, LLC	(15,000)	

Distributions paid to common limited partners and the general partner	(26,349)	(85,621)
Other	(11,239)	(5,352)
Net cash provided by (used in) financing activities	(289,620)	208,687
Net change in cash and cash equivalents	(498)	149,978
Cash and cash equivalents, beginning of period	1,445	12,341
Cash and cash equivalents, end of period	$ 947	$ 161,319

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

JUNE 30, 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 5) and 15,000 $1,000 par value Class B preferred limited partner units (see Note 6). At June 30, 2009, the Partnership had 47,804,175 common limited partnership units outstanding, including the 5,754,253 common units held by the General Partner and 15,000 $1,000 par value Class B preferred units held by the General Partner.

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 June 30, 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). The majority of the natural gas the Partnership and its affiliates, including Laurel Mountain, (see Note 3) 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. Management has evaluated subsequent events through August 7, 2009, the date the financial statements were issued. 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. On May 4, 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system (see Note 4). As such, the Partnership has adjusted the prior period consolidated financial statements and related footnote disclosures presented within this Form 10-Q to reflect the amounts related to the operations of the NOARK gas gathering and interstate pipeline system as discontinued operations. The results of operations for the three and six month periods ended June 30, 2009 may not necessarily be indicative of the results of operations for the full year ending December 31, 2009.

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.

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, which began on June 15, 2009 and ends 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 option.

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 and six months ended June 30, 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 8), 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 15), 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) from continuing operations and net income from discontinued operations allocated to the general partner and common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands, except per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008[1]	2009	2008[1]
Continuing operations:				
Net income (loss)	$ 79,779	$ (283,804)	$ 47,667	$ (333,780)
Income attributable to non-controlling interest	(652)	(3,112)	(1,121)	(5,202)
Preferred unit dividends		(650)	(900)	(787)
Preferred unit imputed dividend cost				(505)
Net income (loss) attributable to common limited partners and the general partner	79,127	(287,566)	45,646	(340,274)
General partner s actual cash incentive distributions declared		8,234		15,234
General partner s actual 2% ownership interest	1,590	(5,945)	917	(7,145)
Net income (loss) attributable to the general partner s ownership interests	1,590	2,289	917	8,089
Net income (loss) attributable to common limited partners	77,537	(289,855)	44,729	(348,363)
Less: net income (loss) attributable to participating securities phantom units[2]	135	(1,187)	96	(1,354)
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$ 77,402	$ (288,668)	$ 44,633	$ (347,009)
Discontinued operations:				
Net income	$ 53,619	$ 8,245	$ 62,495	$ 14,491
Net income attributable to the general partner s ownership interests (2% ownership interest)	1,078	166	1,256	291
Net income utilized in the calculation of net income from discontinued operations attributable to common limited partners per unit	$ 52,541	$ 8,079	$ 61,239	$ 14,200

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

(2) 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).

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 15). 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 June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Weighted average common limited partner units basic	47,529	39,329	46,755	39,046
Add: effect of dilutive option incentive awards[1]				
Add: effect of dilutive convertible preferred limited partner units[1]				
Weighted average common limited partner units diluted	47,529	39,329	46,755	39,046

(1) For the three and six months ended June 30, 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 or six months ended June 30, 2008. For the three and six months ended June 30, 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 6 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 income (loss) (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Net income (loss)	$ 133,398	$ (275,559)	$ 110,162	$ (319,289)
Income attributable to non-controlling interests	(652)	(3,112)	(1,121)	(5,202)
Preferred unit dividends		(650)	(900)	(787)
Preferred unit imputed dividend cost				(505)
Net income (loss) attributable to common limited partners and the general partner	132,746	(279,321)	108,141	(325,783)
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as hedges	(1,006)	(127,994)	(2,298)	(109,409)
Add: adjustment for realized losses reclassified to net income (loss)	13,856	18,663	32,719	36,306
Total other comprehensive income (loss)	12,850	(109,331)	30,421	(73,103)
Comprehensive income (loss)	$ 145,596	$ (388,652)	$ 138,562	$ (398,886)

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

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 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.

Revenue in the Partnership s Appalachia segment is principally recognized at the time the natural gas is transported through its gathering systems.

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 June 30, 2009 and December 31, 2008 of $45.9 million and $50.1 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 5.8% and 5.9% for the three months ended June 30, 2009 and 2008, respectively, and 5.3% and 6.3% for the six months ended June 30, 2009 and 2008, respectively. The amount of interest capitalized was $0.5 million and $1.9 million for the three months ended June 30, 2009 and 2008, respectively, and $1.9 million and $3.5 million for the six months ended June 30, 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 June 30, 2009 and December 31, 2008 (in thousands):

	June 30, 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	$ (6,602)	$ (5,806)	
Customer relationships	(47,911)	(35,929)	
	$ (54,513)	$ (41,735)	
Net Carrying Amount:			
Customer contracts	$ 6,208	$ 7,004	
Customer relationships	174,661	186,643	
	$ 180,869	$ 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 month periods ended June 30, 2009 and 2008, and $12.8 million for both the six month periods ended June 30, 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 six months ended June 30, 2009 and 2008 were as follows (in thousands):

	Six Months Ended June 30,	
	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		(2,217)
Recovery of state sales tax initially paid on transaction Chaney Dell and Midkiff/ Benedum acquisition		(30,206)
Balance, end of period	$	$ 676,860

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 June 30, 2008.

Recently Adopted Accounting Standards

In May 2009, the FASB issued Statement No. 165, Subsequent Events (SFAS No. 165). SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS No. 165 requires management of a reporting entity to evaluate events or transactions that may occur after the balance sheet date for potential recognition or disclosure in the financial statements and provides guidance for disclosures that an entity should make about those events. SFAS No. 165 is effective for interim or annual financial periods ending after June 15, 2009 and shall be applied prospectively. The Partnership adopted the requirements of SFAS No. 165 on June 30, 2009 and it did not have a material impact to its financial position or results of operations or related disclosures. The adoption of SFAS 165 does not change the Partnership s current practices with respect to evaluating, recording and disclosing subsequent events.

In April 2009, the FASB issued Staff Position 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly (FSP FAS 157-4). FSP FAS 157-4 applies to all fair value measurements and provides additional clarification on estimating fair value when the market activity for an asset has declined significantly. FSP FAS 157-4 also requires an entity to disclose a change in valuation technique and related inputs to the valuation calculation and to quantify its effects, if practicable. FSP FAS 157-4 is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Partnership adopted the requirements of FSP FAS 157-4 on April 1, 2009 and its adoption did not have a material impact on the Partnership s financial position and results of operations.

In April 2009, the FASB issued Staff Position 115-2 and 124-2, Recognition and Presentation of Other-Than-Temporary Impairments (FSP FAS 115-2 and FAS 124-2). FSP FAS 115-2 and FAS 124-2 change existing guidance for determining whether an impairment is other than temporary for debt securities. FSP FAS 115-2 and FAS 124-2 replaces the existing requirement that an entity s management assess it has both the intent and ability to hold an impaired security until recovery with a requirement that management assess that it does not have the intent to sell the security and that it is more likely than not that it will not have to sell the security before recovery of its cost basis. FSP FAS 115-2 and FAS 124-2 also requires that an entity recognize noncredit losses on held-to-maturity debt securities in other comprehensive income and amortize that amount over the remaining life of the security and for the entity to present the total other-than-temporary impairment in the statement of operations with an offset for the amount recognized in other comprehensive income. FSP FAS 115-2 and FAS 124-2 are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Partnership adopted the requirements of FSP FAS 115-2 and FAS 124-2 on April 1, 2009 and its adoption did not have a material impact on the Partnership s financial position and results of operations.

In April 2009, the FASB issued Staff Position 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP FAS 107-1 and APB 28-1). FSP FAS 107-1 APB 28-1 requires an entity to provide disclosures about fair value of financial instruments in interim financial information. In addition, an entity shall disclose in the body or in the accompanying notes of its summarized financial information for interim reporting periods and in its financial statements for annual reporting periods the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. FSP FAS 107-1 APB 28-1 is effective for interim periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. The Partnership adopted the requirements of FSP FAS 107-1 APB 28-1 on April 1, 2009 and its adoption did not have a material impact on the Partnership s financial position and results of operations.

In April 2009, the FASB issued Staff Position 141(R)-1, Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies (FSP 141(R)-1). FSP 141(R)-1 requires that assets acquired and liabilities assumed in a business combination that arise from contingencies be recognized at fair value if fair value can be reasonably estimated. If fair value of such an asset or liability cannot be reasonably estimated, the asset or liability would generally be recognized in accordance with FASB Statement No. 5, Accounting for Contingencies and FASB Interpretation No. 14, Reasonable Estimation of the Amount of a Loss . FSP 141(R)-1 also eliminates the requirement to disclose an estimate of the range of outcomes of recognized contingencies at the acquisition date. FSP FAS 141(R)-1 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for the Partnership). The Partnership adopted the requirements of FSP 141(R)-1 on January 1, 2009 and its adoption did not have a material impact on the Partnership s financial position and results of operations.

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.

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 11).

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. SFAS No. 160 also requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated and adjust its remaining investment, if any, at fair value. 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.

Recently Issued Accounting Standards

In June 2009, the FASB issued Statement No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles A Replacement of FASB Statement No. 162 (SFAS No. 168). SFAS No. 168 establishes the FASB Accounting Standards Codification (Codification) as the single source of authoritative U.S. generally accepted accounting principles recognized by the FASB to be applied by nongovernmental entities. The Codification supersedes all existing non-Securities and Exchange Commission accounting and reporting standards. Following SFAS No. 168, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, the FASB will issue Accounting Standards Updates, which will serve only to update the Codification. SFAS No. 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Partnership will apply the requirements of SFAS No. 168 to its financial statements for the interim period ending September 30, 2009 and does not expect it to have a material impact to its financial position or results of operations or related disclosures.

In June 2009, the FASB issued Statement No. 167, Amendments to FASB Interpretation No. 46(R) (SFAS No. 167). SFAS No. 167 is a revision to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities and changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. SFAS No. 167 requires a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. A reporting entity will be required to disclose how its involvement with a variable interest entity affects the reporting entity s financial statements. SFAS No. 167 is effective at the start of a reporting entity s first fiscal year beginning after November 15, 2009 (January 1, 2010 for the Partnership). The Partnership will apply the requirements of SFAS No. 167 upon its adoption on January 1, 2010 and does not expect it to have a material impact to its financial position or results of operations or related disclosures.

NOTE 3 INVESTMENT IN JOINT VENTURE

On May 31, 2009, the Partnership and subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) completed the formation of Laurel Mountain Midstream LLC (Laurel Mountain), a joint venture which 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 contributed cash of $100.0 million, of which the Partnership received approximately $87.8 million, net of working capital adjustments, and a note receivable of $25.5 million. The Partnership contributed the Appalachia Basin natural gas gathering system and retained a 49% ownership interest in Laurel Mountain. The Partnership is also entitled to preferred distribution rights relating to all payments on the note receivable. Williams retained the remaining 51% ownership interest in Laurel Mountain. Upon completion of the transaction, the Partnership recognized its 49% ownership interest in Laurel Mountain as an investment in joint venture on its consolidated balance sheet at fair value and recognized a gain on sale of $109.9 million, including $79.7 million associated with the remeasurement of the Partnership s investment in Laurel Mountain to fair value. The Partnership used the net proceeds from the transaction to reduce borrowings under its senior secured credit facility (see Note 13). In addition, Atlas Energy sold to Laurel Mountain two natural gas processing plants and associated pipelines located in Southwestern Pennsylvania for $10.0 million. Upon the completion of the contribution of the Partnership s Appalachia gathering systems to Laurel Mountain, Laurel Mountain entered into new gas gathering agreements with Atlas Energy which superseded the existing natural gas gathering agreements and omnibus agreement between the Partnership and Atlas Energy. Under the new gas gathering agreement, Atlas Energy is obligated to pay the joint venture all of the gathering fees it collects from its investment drilling 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 Partnership has accounted for its ownership interest in Laurel Mountain under the equity method of accounting, with recognition of its ownership interest in the income of Laurel Mountain as equity income on its consolidated statements of operations.

The following table provides summarized statement of operations and balance sheet data on a 100 % basis for Laurel Mountain for the three and six months ended June 30, 2009 and as of June 30, 2009 (in thousands):

	Three Months Ended June 30, 2009[1]	Six Months Ended June 30, 2009[1]
Statement of Operations data:		
Total revenue	$ 3,068	$ 3,068
Net income	1,278	1,278
	June 30, 2009	
Balance Sheet data:		
Current assets	$ 7,565	
Long-term assets	245,395	
Current liabilities	11,104	
Long-term liabilities	15,500	
Net equity	226,356	

(1) Represents the period from May 31, 2009, the date of initial formation, through June 30, 2009.

NOTE 4 DISCONTINUED OPERATIONS

On May 4, 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE:SEP) (Spectra) for net proceeds of $292.0 million in cash, net of working capital adjustments. The Partnership received an additional $2.5 million in cash in July 2009 upon the delivery of audited financial statements for the NOARK system assets to Spectra (see Note 19). The Partnership used the net proceeds from the transaction to reduce borrowings under its senior secured term loan and revolving credit facility (see Note 13). The Partnership accounted for the sale of the NOARK system assets as discontinued operations within its consolidated financial statements and recorded a gain of $51.1 million on the sale of the NOARK assets within income from discontinued operations on its consolidated statements of operations for the three and six months ended June 30, 2009. The following table summarizes the components included within income from discontinued operations on the Partnership s consolidated statements of operations (amounts in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Total revenue and other loss, net	$ 5,269	$ 15,988	$ 21,274	$ 32,359
Total costs and expenses	(2,728)	(7,743)	(9,857)	(17,868)
Income from discontinued operations	$ 2,541	$ 8,245	$ 11,417	$ 14,491

The following table summarizes the components included within total assets and liabilities of discontinued operations within the Partnership s consolidated balance sheet for the period indicated (amounts in thousands):

	December 31, 2008
Cash and cash equivalents	$ 75
Accounts receivable	12,365
Prepaid expenses and other	1,001
Total current assets of discontinued operations	13,441
Property, plant and equipment, net	241,926
Other assets, net	239
Total assets of discontinued operations	$ 255,606
Accounts payable	$ 4,120
Accrued liabilities	5,892
Accrued producer liabilities	560
Total current liabilities of discontinued operations	$ 10,572

NOTE 5 COMMON UNIT EQUITY OFFERING

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 11).

NOTE 6   PREFERRED UNIT EQUITY OFFERINGS

Class A Preferred Units

In January 2009, the Partnership and Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, agreed to amend certain terms of the preferred unit certificate of designation for the then-outstanding 30,000 $1,000 par value 12.0% cumulative convertible Class A preferred units of limited partner interests (the Class A Preferred Units), 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 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 13) 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 within the Partnership s 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) the Partnership 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, the Partnership has the option of redeeming the Class A Preferred Units for cash at the stipulated liquidation value or converting the Class A Preferred Units into its 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 would have been required to be redeemed in cash, while the Partnership had the option of redeeming the remaining 5,000 Class A Preferred Units in cash or converting the preferred units into its common limited partner units.

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, in accordance with the terms of the amended preferred units certificate of designation. Additionally on April 1, 2009, the Partnership paid Sunlight a preferred dividend of $0.3 million, representing the quarterly dividend on the 10,000 preferred units held by Sunlight prior to the Partnership s redemption. On April 13, 2009, the Partnership converted 5,000 of the Class A Preferred Units into 1,465,653 Partnership common units in accordance with the terms of the amended preferred units certificate of designation. The Partnership reclassified $5.0 million from Class A preferred limited partner equity to common limited partner equity within partners capital when these preferred units were converted into common limited partner units. On May 5, 2009, the Partnership redeemed the remaining 5,000 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. 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.

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 for the six months ended June 30, 2008.

The Partnership recognized $0.7 million of preferred dividend cost for the three months ended June 30, 2008 and $0.4 million and $0.8 million of preferred dividend cost for the six months ended June 30, 2009 and 2008, respectively, for dividends paid to the Class A preferred units, 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.

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. The Partnership recognized $0.5 million of preferred dividend cost for the six months ended June 30, 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 Class B Preferred Units are reflected on the Partnership s consolidated balance sheet as Class B preferred equity within partners capital.

NOTE 7 INVESTMENT IN ATLAS PIPELINE HOLDINGS II, LLC

On June 1, 2009, the Partnership purchased 15,000 12.0% cumulative preferred units (the preferred units) from a newly-formed subsidiary of AHD, Atlas Pipeline Holdings II, LLC (AHD II) for cash consideration of $1,000 per unit, for an aggregate investment of $15.0 million at June 30, 2009. The preferred units receive cash distributions of 12.0% per annum, to be paid quarterly. However, per the terms of AHD s amended agreement to its outstanding revolving credit facility, such distributions can be paid only upon AHD s repayment of all of its outstanding borrowings under its credit facility, which will occur no later than April 13, 2010, the credit facility s maturity date. Distributions on the Partnership s preferred units held by AHD II prior to AHD s repayment of all indebtedness under its credit facility will be paid by increasing the Partnership s preferred unit investment in AHD II. AHD II has the option, beginning on April 14, 2010, to redeem all of its outstanding preferred units held by the Partnership for an amount equal to the Partnership s then-current balance of its preferred unit investment. AHD used the proceeds from its preferred unit offering to the Partnership to reduce indebtedness under its credit facility. The Partnership accounted for the purchase of the preferred units as treasury units, with the investment reflected at cost as a reduction of partners capital within its consolidated balance sheet.

NOTE 8 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 June 30, 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
May 15, 2009	March 31, 2009	$ 0.15	$ 7,149	$ 147

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.

The Partnership did not declare a cash distribution for the quarter ended June 30, 2009. On May 29, 2009, the Partnership entered into an amendment to its senior secured credit facility (see Note 13) which, among other changes, requires that it pay no cash distributions during the remainder of the year ended December 31, 2009 and allows it to pay cash distributions beginning January 1, 2010 if its senior secured leverage ratio is above certain thresholds and it has minimum liquidity (both as defined in the credit agreement) of at least $50.0 million.

NOTE 9 PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2009	December 31, 2008[(1)]	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,657,201	$ 1,707,046	15 40
Rights of way	166,595	168,057	20 40
Buildings	8,923	8,920	40
Furniture and equipment	9,417	9,279	3 7
Other	12,736	13,002	3 10
	1,854,872	1,906,304	
Less accumulated depreciation	(128,845)	(125,293)	
	$ 1,726,027	$ 1,781,011	

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

NOTE 10 OTHER ASSETS

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

	June 30, 2009	December 31, 2008[(1)]
Deferred finance costs, net of accumulated amortization of $21,951 and $17,298 at June 30, 2009 and December 31, 2008, respectively	$ 30,371	$ 23,676
Long-term pipeline lease prepayment	2,043	
Security deposits	1,663	1,317
	$ 34,077	$ 24,993

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

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). During May 2009, the Partnership recorded $2.3 million of accelerated amortization of deferred financing costs associated with the retirement of a portion of its term loan with the proceeds from the sale of its NOARK system (see Note 4). During June 2008, the Partnership recorded $1.2 million for accelerated amortization of deferred financing costs associated with the retirement of a portion of its term loan with a portion of the net proceeds from its issuance of senior notes (see Note 13).

NOTE 11 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 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 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.

During the six months ended June 30, 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 and six months ended June 30, 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			
	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2009	**2008**	**2009**	**2008**
Net cash derivative expense included within other loss, net	$	$ (115,810)	$ (5,000)	$ (115,810)
Net cash derivative expense included within natural gas and liquids revenue		(315)		(315)
Net non-cash derivative income (expense) included within other loss, net	7,117	(46,345)	19,220	(46,345)
Net non-cash derivative expense included within natural gas and liquids	(12,123)		(34,067)	

In addition, $13.4 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 July 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 June 30, 2009, the Partnership had interest rate derivative contracts having aggregate notional principal amounts of $450.0 million. 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 credit facility (see Note 13), and will receive LIBOR, plus the applicable margin, on the notional principal amounts. The interest rate swap agreements were in effect as of June 30, 2009 and expire during periods ranging from January 30, 2010 through April 30, 2010. Beginning May 29, 2009, the Partnership discontinued hedge accounting for its interest rate derivatives which were qualified as hedges under SFAS No. 133. As such, subsequent changes in the fair value of these derivatives will be recognized immediately within other loss, net in its consolidated statements of operations. The fair value of these derivative instruments at May 29, 2009, which was recognized in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. At June 30, 2009 and December 31, 2008, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $67.0 million and $63.6 million, respectively. Of the $74.5 million of net loss in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet at June 30, 2009, if the fair values of the instruments remain at current market values, the Partnership will reclassify $42.0 million of losses to the Partnership s consolidated statements of operations over the next twelve month period, consisting of $33.8 million of losses to natural gas and liquids revenue and $8.2 million of losses to interest expense. Aggregate losses of $32.5 million will be reclassified to the Partnership s consolidated statements of operations in later periods, all consisting of losses to natural gas and liquids revenue. 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):

	June 30, 2009	December 31, 2008
Current portion of derivative asset	$ 1,815	$ 44,961
Long-term derivative asset	1,606	
Current portion of derivative liability	(57,660)	(60,396)
Long-term derivative liability	(12,748)	(48,159)
	$ (66,987)	$ (63,594)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Loss from cash and non-cash settlement of qualifying hedge instruments(1)	$ (7,327)	$ (33,152)	$ (27,502)	$ (50,795)
Gain (loss) from change in market value of non-qualifying derivatives(2)	2,509	(136,736)	(42,481)	(207,932)
Gain (loss) from change in market value of ineffective portion of qualifying derivatives(2)		1,934	10,813	(3,726)
Gain (loss) from cash and non-cash settlement of non-qualifying derivatives(2)	(21,105)	(184,564)	13,390	(196,489)
Loss from cash settlement of interest rate derivatives(3)	(2,962)	(194)	(5,855)	(194)

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

(2) Included within other 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):

	June 30, 2009			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments under SFAS No. 133:				
N/A				
Derivatives not designated as hedging instruments under SFAS No. 133:				
Interest rate contracts			Current portion of derivative liability	$ (8,171)
Commodity contracts	Current portion of derivative asset	1,815		
Commodity contracts	Long-term derivative asset	1,606		
Commodity contracts	Current portion of derivative liability	6,848	Current portion of derivative liability	(56,337)
Commodity contracts	Long-term derivative liability	3,151	Long-term derivative liability	(15,899)
		$ 13,420		$ (80,407)

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):

	Three months ended June 30, 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:				
N/A				
Derivatives not designated as hedging instruments under SFAS No. 133:				
Interest rate contracts	$ (2,962)	Interest expense	$	N/A
Commodity contracts(1)	$ (10,894)	Natural gas and liquids revenue	$ (13,381)	Other loss, net
Commodity contracts(2)		N/A	(4,155)	Other loss, net
	$ (13,856)		$ (17,536)	

(1) Hedges previously designated as cash flow hedges

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

	Six months ended June 30, 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:				
N/A				
Derivatives not designated as hedging instruments under SFAS No. 133:				
Interest rate contracts	$ (5,855)	Interest expense	$	N/A
Commodity contracts[1]	$ (26,864)	Natural gas and liquids revenue	$ (22,908)	Other loss, net
Commodity contracts[2]		N/A	35,665	Other loss, net
	$ (32,719)		$ 12,757	

(1) Hedges previously designated as cash flow hedges

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

As of June 30, 2009, the Partnership had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Interest Fixed-Rate Swap

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	$ (2,480)
				2010	(351)
					$ (2,831)
April 2008- April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2009	$ (3,430)
				2010	(1,910)
					$ (5,340)

Natural Gas Liquids Sales   Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[(2)] (in thousands)
2009	11,088,000	$ 0.745	$ (573)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Price [(4)] (per barrel)	Fair Value Asset/ (Liability)[(3)] (in thousands)	Option Type
2009	234,000	13,185,000	$ 60.97	$ 1,234	Puts purchased
2009	1,055,400	59,081,820	$ 84.75	(2,622)	Calls sold
2010	486,000	27,356,700	$ 61.24	3,838	Puts purchased
2010	3,127,500	213,088,050	$ 86.20	(22,103)	Calls sold
2010	714,000	45,415,440	$ 132.17	708	Calls purchased[(4)]
2011	606,000	33,145,560	$ 100.70	(4,065)	Calls sold
2011	252,000	13,547,520	$ 133.16	764	Calls purchased[(4)]
2012	450,000	25,893,000	$ 102.71	(3,746)	Calls sold
2012	180,000	9,676,800	$ 134.27	801	Calls purchased[(4)]
				$ (25,191)	

Natural Gas Sales   Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)[(5)]	Average Fixed Price (per mmbtu) [(6)]	Fair Value Asset[(3)] (in thousands)
2009	240,000	$ 8.000	$ 866

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)[(5)]	Average Fixed Price (per mmbtu)[(6)]	Fair Value Asset[(3)] (in thousands)
2009	2,460,000	$ (0.558)	$ 27
2010	2,220,000	$ (0.607)	124
			$ 151

Natural Gas Purchases   Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)[(5)]	Average Fixed Price (per mmbtu)[(6)]	Fair Value Liability[(3)] (in thousands)

2009	5,160,000	$ 8.687	$ (22,156)
2010	4,380,000	$ 8.635	(12,414)
			$ (34,570)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)[5]	Average Fixed Price (per mmbtu)[6]	Fair Value Liability[3] (in thousands)
2009	7,380,000	$ (0.659)	$ (83)
2010	6,600,000	$ (0.590)	(111)
			$ (194)

Ethane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price(4) (per gallon)	Fair Value Liability(1) (in thousands)	Option Type
2009	630,000	$ 0.340	$ (40)	Puts purchased

Propane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price(4) (per gallon)	Fair Value Asset(1) (in thousands)	Option Type
2009	15,498,000	$ 0.767	$ 752	Puts purchased

Isobutane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price(4) (per gallon)	Fair Value Asset (1) (in thousands)	Option Type
2009	1,134,000	$ 0.969	$ 20	Puts purchased

Normal Butane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price(4) (per gallon)	Fair Value Asset(1) (in thousands)	Option Type
2009	9,324,000	$ 0.964	$ 585	Puts purchased

Natural Gasoline Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price(4) (per gallon)	Fair Value Asset(1) (in thousands)	Option Type
2009	5,796,000	$ 1.267	$ 358	Puts purchased

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability(3) (in thousands)
2009	15,000	$ 62.700	$ (131)

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Crude Price[(4)] (per barrel)	Fair Value Asset(Liability)[(3)] (in thousands)	Option Type
2009	231,000	$ 63.017	$ 1,100	Puts purchased
2009	153,000	$ 84.881	(434)	Calls sold
2010	174,000	$ 61.111	1,361	Puts purchased
2010	234,000	$ 88.088	(1,557)	Calls sold
2011	72,000	$ 93.109	(699)	Calls sold
2012	48,000	$ 90.314	(620)	Calls sold
			$ (849)	
		Total net liability	$ (66,987)	

(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) Average price of options based upon average strike price adjusted by average premium paid or received.

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

(6) Mmbtu represents million British Thermal Units.

NOTE 12 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 11). All of the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and NGL options. The Partnership s Level 2 commodity 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 NGL options are based on forward price curves developed by the related financial institution, 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 June 30, 2009 (in thousands):

	Level 1	Level 2	Level 3	Total
Commodity-based derivatives	$	$ (59,919)	$ 1,103	$ (58,816)
Interest rate swap-based derivatives		(8,171)		(8,171)
Total	$	$ (68,090)	$ 1,103	$ (66,987)

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments as of June 30, 2009 (in thousands):

	NGL Fixed Price Swaps	NGL Sales Options	Total
Balance December 31, 2008	$ 1,509	$ 12,316	$ 13,825
New options contracts		(1,024)	(1,024)
Cash settlements from unrealized gain (loss)[1]	(4,215)	(11,410)	(15,625)
Cash settlements from other comprehensive income[1]	3,700		3,700
Net change in unrealized gain (loss)[2]	(1,567)	(1,061)	(2,628)
Deferred option premium recognition		2,855	2,855
Net change in other comprehensive loss			
Balance June 30, 2009	$ (573)	$ 1,676	$ 1,103

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

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

Other Financial Instruments

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

The Partnership s other current assets and liabilities on its consolidated balance sheets are financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature. The estimated fair values of the Partnership s total debt at June 30, 2009 and December 31, 2008, which consists principally of the term loan, the Senior Notes and borrowings under the credit facility, was $1,110.0 million and $1,153.2 million, respectively, compared with the carrying amount of $1,276.3 million and $1,493.4 million, respectively. The term loan and Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

NOTE 13 DEBT

Total debt consists of the following (in thousands):

	June 30, 2009	December 31, 2008
Revolving credit facility	$ 322,000	$ 302,000
Term loan	459,885	707,180
8.125% Senior notes due 2015	271,365	261,197
8.75% Senior notes due 2018	223,050	223,050
Total debt	1,276,300	1,493,427
Less current maturities		
Total long-term debt	$ 1,276,300	$ 1,493,427

Term Loan and Revolving Credit Facility

At June 30, 2009, the Partnership has 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 June 30, 2009 was 6.8%, and the weighted average interest rate on the outstanding term loan borrowings at June 30, 2009 was 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $3.5 million was outstanding at June 30, 2009. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet.

On May 29, 2009, the Partnership entered into an amendment to its credit facility agreement which, among other changes:

increased the applicable margin above adjusted LIBOR, the federal funds rate plus 0.5% or the Wachovia Bank prime rate upon which borrowings under the credit facility bear interest;

for borrowings under the credit facility that bear interest at LIBOR plus the applicable margin, set a floor for the adjusted LIBOR interest rate of 2.0% per annum;

increased the maximum ratios of funded debt (as defined in the credit agreement) to consolidated EBITDA (as defined in the credit agreement; the leverage ratio) and interest coverage (as defined in the credit agreement) that the credit facility requires the Partnership to maintain;

instituted a maximum ratio of senior secured debt (as defined in the credit agreement) to consolidated EBITDA (the senior secured leverage ratio) that the credit facility requires the Partnership to maintain;

requires that the Partnership pay no cash distributions during the remainder of the year ended December 31, 2009 and allows the Partnership to pay cash distributions beginning January 1, 2010 if its senior secured leverage ratio is less than 2.75x and has minimum liquidity (as defined in the credit agreement) of at least $50.0 million;

generally limits the Partnership s annual capital expenditures to $95.0 million for the remainder of fiscal 2009 and $70.0 million each year thereafter;

permitted the Partnership to retain (i) up to $135.0 million of net cash proceeds from dispositions completed in fiscal 2009 for reinvestment in similar replacement assets within 360 days, and (ii) up to $50.0 million of net cash proceeds from dispositions completed in any subsequent fiscal year subject to certain limitations as defined within the credit agreement; and

instituted a mandatory repayment requirement of the outstanding senior secured term loan from excess cash flow (as defined in the credit agreement) based upon the Partnership s leverage ratio.

In June 2008, the Partnership entered into an amendment to the credit facility agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to its early termination of certain derivative contracts (see Note 11) in calculating 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 revolving credit facility with proceeds from its issuance of $250.0 million of 10-year 8.75% senior unsecured 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 Chaney Dell and Midkiff/Benedum joint ventures and the Partnership s investment in the Laurel Mountain joint venture, and by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is also unable to borrow under its credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement. The Partnership is in compliance with these covenants as of June 30, 2009.

The events which constitute an event of default for the credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner. The credit facility requires the Partnership to maintain the following ratios:

Fiscal quarter ending:	**Maximum Leverage Ratio**	**Maximum Senior Secured Leverage Ratio**	**Minimum Interest Coverage Ratio**
June 30, 2009	5.50x	3.00x	2.50x
September 30, 2009	6.50x	3.75x	2.50x
December 31, 2009	8.50x	5.25x	1.70x
March 31, 2010	9.25x	5.75x	1.40x
June 30, 2010	8.00x	5.00x	1.65x
September 30, 2010	7.00x	4.25x	1.90x
December 31, 2010	6.00x	3.75x	2.20x
Thereafter	5.00x	3.00x	2.75x

As of June 30, 2009, the Partnership s leverage ratio was 3.6 to 1.0, its senior secured leverage ratio was 2.2 to 1.0, and its interest coverage ratio was 4.2 to 1.0.

Senior Notes

At June 30, 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 $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with a net $4.1 million of unamortized discount as of June 30, 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 6). 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 is 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 within 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 June 30, 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 14 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 June 30, 2009, the Partnership is committed to expend approximately $19.2 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). These matters were previously described in the Partnership s quarterly report on Form 10-Q for the quarter ended March 31, 2009. Both matters were settled by agreement dated May 19, 2009. The settlement involved a monetary payment by Elk City, but does not require Elk City to purchase the pipeline assets. The amounts Elk City agreed to pay in connection with the settlement do not have a material impact on the Partnership s financial condition or results of operations.

NOTE 15 BENEFIT PLANS

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 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 June 30, 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 June 30, 2009, 29,376 units will vest within the following twelve months. All phantom units outstanding under the LTIP at June 30, 2009 include DERs granted to the participants by the Committee. The amounts paid with respect to LTIP DERs were $11,000 and $0.2 million for the three months ended June 30, 2009 and 2008, respectively, and $0.1 million and $0.3 million for the six months ended June 30, 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Outstanding, beginning of period	101,929	171,087	126,565	129,746
Granted[(1)]	500	345	2,000	54,296
Matured[(2)]	(25,208)	(21,509)	(35,094)	(33,369)
Forfeited	(500)		(16,750)	(750)
Outstanding, end of period[(3)]	76,721	149,923	76,721	149,923
Non-cash compensation expense recognized (in thousands)	$ 351	$ 697	$ 256	$ 1,183

(1) The weighted average prices for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense and does not represent an exercise price to be paid by the recipient, were $5.20 and $43.42 for awards granted for the three months ended June 30, 2009 and 2008, respectively, and $4.75 and $44.43 for awards granted for the six months ended June 30, 2009 and 2008, respectively.

(2) The intrinsic values for phantom unit awards vested during the three months ended June 30, 2009 and 2008 were $0.1 million and $0.9 million, respectively, and $0.2 million and $1.4 million during the six months ended June 30, 2009 and 2008, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2009 was $0.6 million.

At June 30, 2009, the Partnership had approximately $1.1 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 period for unit options. Unit option awards expire 10 years from the date of grant. Through June 30, 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 June 30, 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 June 30,			
	2009		2008	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	100,000	$ 6.24		
Granted				
Matured				
Forfeited				
Outstanding, end of period[(1)(2)]	100,000	$ 6.24		

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

	Six Months Ended June 30,			
	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				
Weighted average fair value of unit options per unit granted during the period				
Weighted average fair value of unit	100,000	$ 0.14		
Non-cash compensation expense recognized (in thousands)	$ 4			

(1) The weighted average remaining contractual life for outstanding options at June 30, 2009 was 9.5 years.

(2) The aggregate intrinsic value of options outstanding at June 30, 2009 was $0.2 million.

At June 30, 2009, the Partnership had approximately $10,000 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 & Six Months Ended June 30, 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 and six months ended June 30, 2009. The Partnership recognized compensation expense of $0.5 million and a reduction compensation expense of $2.8 million for the three and six months ended June 30, 2008 related to the vesting of awards under these incentive compensation agreements. The non-cash compensation expense adjustments for the three and six months ended June 30, 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 June 30, 2008 when compared with the common unit market price at earlier periods and adjustments based upon the achievement of actual financial performance targets through June 30, 2008. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method. During the six months ended June 30, 2009, the Partnership issued 348,620 common units to the certain key employees covered under the incentive compensation agreements. No additional common units will be issued with regard to these agreements.

Executive Incentive Plan

In June 2009, the Partnership adopted an executive incentive plan (the Plan), which provides cash incentive awards to certain employees of the Partnership, but not Named Executive Officers of the Partnership, as defined under Securities and Exchange Commission regulations (the Plan Participants). The Plan is administered by a committee (the Plan Committee) appointed by the Partnership s chief executive officer. Under the Plan, cash bonus units (Bonus Unit) may be awarded to the Plan Participants at the discretion of the Plan Committee. A Bonus Unit entitles a Plan Participant to receive the cash equivalent of the then-fair market value of a Partnership common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. The Plan Committee will determine the vesting period for Bonus Units. Through June 30, 2009, Bonus Units granted under the Plan vest ratably over a three year period from the date of grant. Awards under the Plan will automatically vest upon a change of control of the Partnership, as defined in the Plan, and vesting will terminate upon termination of employment. During the three and six months ended June 30, 2009, the Plan Committee granted 325,000 Bonus Units to Plan Participants under the Plan. Of the Bonus Units outstanding under the Plan at June 30, 2009, 107,250 Bonus Units will vest within the following twelve months. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value. During the three and six months ended June 30, 2009, the Partnership recognized $0.1 million of compensation expense within general and administrative expense on its consolidated statements of operations with respect to the vesting of these awards. At June 30, 2009, the Partnership has recognized $0.1 million within accrued liabilities on its consolidated balance sheet with regard to the awards, which represents their fair value at June 30, 2009.

NOTE 16 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 \$1.4 million for the three months ended June 30, 2009 and 2008, respectively, and \$0.8 million and \$2.5 million for the six months ended June 30, 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 and six months ended June 30, 2009 and 2008. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

NOTE 17 SEGMENT INFORMATION

The Partnership has two reportable segments: natural gas transmission, gathering and processing assets located in the Mid-Continent area (Mid-Continent) of primarily Oklahoma, northern and western Texas, the Texas Panhandle and southern Kansas, and natural gas transmission, gathering and processing assets located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee. Effective May 29, 2009, the Appalachia operations were principally conducted through the Partnership s 49% ownership interest in Laurel Mountain, a joint venture to which the Partnership contributed its natural gas transmission, gathering and processing assets located in eastern Ohio, western New York, and western Pennsylvania. The Partnership recognizes its ownership interest in Laurel Mountain under the equity method of accounting. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and transport of natural gas. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates. 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 June 30, 2009	Three Months Ended June 30, 2008[(1)]	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008[(1)]
Mid-Continent				
Revenue:				
Natural gas and liquids	$ 176,674	$ 429,211	$ 331,453	$ 787,866
Transportation, compression and other fees	3,519	5,350	7,012	10,099
Other loss, net	(15,711)	(314,348)	(10,635)	(401,214)
Total revenue and other loss, net	164,482	120,213	327,830	396,751
Costs and expenses:				
Natural gas and liquids	129,595	349,206	264,151	622,550
Plant operating	14,128	14,831	27,951	29,766
General and administrative	4,956	6,514	13,270	8,663
Depreciation and amortization	21,619	18,868	42,368	37,533
Total costs and expenses	170,298	389,419	347,740	698,512
Segment loss	$ (5,816)	$ (269,206)	$ (19,910)	$ (301,761)
Appalachia				
Revenue:				
Natural gas and liquids	$ 214	$ 1,123	$ 585	$ 2,083
Transportation, compression and other fees affiliates	6,429	11,421	16,497	20,580
Transportation, compression and other fees third parties	462	321	843	568
Equity income in joint venture	710		710	
Gain on asset sale	109,941		109,941	
Other income, net	66	89	139	200
Total revenue and other income, net	117,822	12,954	128,715	23,431
Costs and expenses:				
Natural gas and liquids	81	505	270	987
Transportation and compression	2,791	2,645	6,122	4,959
General and administrative	792	1,523	1,974	3,007
Depreciation and amortization	1,380	1,544	3,299	2,926
Total costs and expenses	5,044	6,217	11,665	11,879
Segment profit	$ 112,778	$ 6,737	$ 117,050	$ 11,552
Reconciliation of segment profit (loss) to net income (loss):				
Segment profit (loss):				
Mid-Continent	$ (5,816)	$ (269,206)	$ (19,910)	$ (301,761)
Appalachia	112,778	6,737	117,050	11,552
Total segment income (loss)	106,962	(262,469)	97,140	(290,209)
Corporate general and administrative expenses	(791)	(1,521)	(1,973)	(3,006)
Interest expense[(2)]	(26,392)	(19,814)	(47,500)	(40,565)
Income (loss) from continuing operations	79,779	(283,804)	47,667	(333,780)
Income from discontinued operations	53,619	8,245	62,495	14,491

Net income (loss)	$ 133,398	$ (275,559)	$ 110,162	$ (319,289)
Capital Expenditures:				
Mid-Continent	$ 53,842	$ 57,669	$ 120,791	$ 119,156
Appalachia	4,457	8,512	9,703	22,898
	$ 58,299	$ 66,181	$ 130,494	$ 142,054

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

(2) 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.

	June 30, 2009	December 31, 2008[1]
Balance Sheet		
Total assets:		
Mid-Continent	$ 1,993,188	$ 2,018,684
Appalachia	145,266	114,166
Discontinued operations		255,606
Corporate other	31,190	24,740
	$ 2,169,644	$ 2,413,196

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008[1]	2009	2008[1]
Natural gas and liquids:				
Natural gas	$ 57,922	$ 185,117	$ 134,498	$ 322,681
NGLs	98,228	211,033	164,522	409,726
Condensate	8,539	22,324	9,333	35,003
Other[2]	12,199	11,860	23,685	22,539
Total	$ 176,888	$ 430,334	$ 332,038	$ 789,949
Transportation, compression and other fees:				
Affiliates	$ 6,429	$ 11,421	$ 16,497	$ 20,580
Third Parties	3,981	5,671	7,855	10,667
Total	$ 10,410	$ 17,092	$ 24,352	$ 31,247

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

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

NOTE 18 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 June 30, 2009 and December 31, 2008 and for the three and six months ended June 30, 2009 and 2008 include the financial statements of Chaney Dell LLC and Midkiff/Benedum, entities in which the Partnership has 95% ownership interests (see Note 2). The Partnership s consolidated financial statements also include its 49% ownership interest in Laurel Mountain, which the Partnership recognizes as a long-term investment on its consolidated balance sheet and equity income on its consolidated statements of operations under the equity method of accounting (see Note 3). Under the terms of the term loan and revolving credit facility, Chaney Dell LLC, Midkiff/Benedum LLC and Laurel Mountain 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 June 30, 2009 and December 31, 2008 and for the three and six months ended June 30, 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):

Balance Sheet	Parent	Guarantor Subsidiaries	June 30, 2009 Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$ 7	$ 940	$	$	$ 947
Accounts receivable affiliates	1,387,181			(1,387,181)	
Current portion of derivative asset		1,815			1,815
Other current assets		36,812	53,688		90,500
Total current assets	1,387,188	39,567	53,688	(1,387,181)	93,262
Property, plant and equipment, net		619,791	1,106,236		1,726,027
Notes receivable			1,852,950	(1,852,950)	
Equity investments	568,075	180,049		(748,124)	
Investment in joint venture			133,803		133,803
Intangible assets, net		19,836	161,033		180,869
Long-term portion of derivative asset		1,606			1,606
Other assets, net	30,371	3,486	220		34,077
	$ 1,985,634	$ 864,335	$ 3,307,930	$ (3,988,255)	$ 2,169,644
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,275,912	$ 112,912	$ (1,387,181)	$ 1,643
Current portion of derivative liability		57,660			57,660
Other current liabilities	1,813	32,699	54,472		88,984
Total current liabilities	1,813	1,366,271	167,384	(1,387,181)	148,287
Long-term derivative liability		12,748			12,748
Long-term debt, less current portion	1,276,300				1,276,300
Other long-term liability		490			490
Partners capital (deficit)	707,521	(515,174)	3,140,546	(2,601,074)	731,819
	$ 1,985,634	$ 864,335	$ 3,307,930	$ (3,988,255)	$ 2,169,644

			December 31, 2008[1]		
Balance Sheet	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$ 7	$ 1,438	$	$	$ 1,445
Accounts receivable affiliates	1,444,812			(1,444,275)	537
Current portion of derivative asset		44,961			44,961
Current assets discontinued operations		13,441			13,441
Other current assets		37,019	73,977		110,996
Total current assets	1,444,819	96,859	73,977	(1,444,275)	171,380
Property, plant and equipment, net		681,497	1,099,514		1,781,011
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
Long-term assets discontinued operations		242,165			242,165
Other assets, net	23,676	1,135	182		24,993
	$ 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
Current liabilities discontinued operations		10,572			10,572
Other current liabilities	1,870	56,105	91,251		149,226
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, less current portion	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

	Three Months Ended June 30, 2009				
Statement of Operations	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Total revenue and other loss, net	$	$ 106,625	$ 190,594	$ (14,915)	$ 282,304
Total costs and expenses	(26,395)	(75,259)	(115,786)	14,915	(202,525)
Equity income	105,284	20,950		(126,234)	
Income from continuing operations	78,889	52,316	74,808	(126,234)	79,779
Income from discontinued operations		53,619			53,619
Net income	$ 78,889	$ 105,935	$ 74,808	$ (126,234)	$ 133,398

	Three Months Ended June 30, 2008[1]				
Statement of Operations	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Total revenue and other loss, net	$	$ (186,399)	$ 319,566	$	$ 133,167
Total costs and expenses	(33,821))	(136,991)	(246,159)		(416,971)
Equity income (loss)	(258,984)	73,709		185,275	
Income (loss) from continuing operations	(292,805)	(249,681)	73,407	185,275	(283,804)
Income from discontinued operations		8,245			8,245
Net income (loss)	$ (292,805)	$ (241,436)	$ 73,407	$ 185,275	$ (275,559)

	Six Months Ended June 30, 2009				
Statement of Operations	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Total revenue and other loss, net	$	$ 162,691	$ 325,950	$ (32,096)	$ 456,545
Total costs and expenses	(47,529)	(160,124)	(233,321)	32,096	(408,878)
Equity income	103,197	39,254		(142,451)	
Income from continuing operations	55,668	41,821	92,629	(142,451)	47,667
Income from discontinued operations		62,495			62,495
Net income	$ 55,668	$ 104,316	$ 92,629	$ (142,451)	$ 110,162

	Six Months Ended June 30, 2008[1]				
Statement of Operations	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Total revenue and other loss, net	$	$ (159,010)	$ 579,192	$	$ 420,182
Total costs and expenses	(39,766)	(276,664)	(437,532)		(753,962)
Equity income (loss)	(284,232)	142,153		142,079	
Income (loss) from continuing operations	(323,998)	(293,521)	141,660	142,079	(333,780)
Income from discontinued operations		14,491			14,491
Net income (loss)	$ (323,998)	$ (279,030)	$ 141,660	$ 142,079	$ (319,289)

Statement of Cash Flows	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
	Six Months Ended June 30, 2009				
Cashflows from operating activities:					
Net income	$ 55,668	$ 104,316	$ 92,629	$ (142,451)	$ 110,162
Less: income from discontinued operations		62,495			62,495
Net income from continuing operations	55,668	41,821	92,629	(142,451)	47,667
Adjustments to reconcile net income from continuing operations to net cash provided by (used in) operating activities:					
Depreciation and amortization		14,641	31,026		45,667
Non-cash loss on derivative value, net		33,814			33,814
Equity income in joint venture			(710)		(710)
Gain on asset sale		23,316	(133,257)		(109,941)
Distributions received from joint venture			164		164
Non-cash compensation expense	259				259
Amortization of deferred financing costs	4,653				4,653
Net distributions to non-controlling interests			1,280		1,280
Changes in assets and liabilities net of effects of acquisitions	87,134	2,791	787	(86,927)	3,785
Net cash provided by (used in) continuing operations	147,714	116,383	(8,081)	(229,378)	26,638
Net cash provided by discontinued operations		16,935			16,935
Net cash provided by (used in) operating activities	147,714	133,318	(8,081)	(229,378)	43,573
Net cash provided by (used in) continuing investing activities	141,906	12,671	(43,474)	(156,148)	(45,045)
Net cash provided by discontinued investing activities		290,594			290,594
Net cash provided by (used in) investing activities	141,906	303,265	(43,474)	(156,148)	245,549
Net cash provided by (used in) financing activities	(289,620)	(437,081)	51,555	385,526	(289,620)
Net change in cash and cash equivalents		(498)			(498)
Cash and cash equivalents, beginning of period	7	1,438			1,445
Cash and cash equivalents, end of period	$ 7	$ 940	$	$	$ 947

	Six Months Ended June 30, 2008[1]				
Statement of Cash Flows	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Cashflows from operating activities:					
Net income (loss)	$ (324,491)	$ (278,537)	$ 141,660	$ 142,079	$ (319,289)
Less: income from discontinued operations		14,491			14,491
Net income (loss) from continuing operations	(324,491)	(293,028)	141,660	142,079	(333,780)
Adjustments to reconcile net income (loss) from continuing operations to net cash provided by (used in) operating activities:					
Depreciation and amortization		11,786	28,673		40,459
Non-cash loss on derivative value, net		201,834			201,834
Non-cash compensation income	(1,600)				(1,600)
Amortization of deferred financing costs	2,608				2,608
Net distributions to non-controlling interests			(5,052)		(5,052)
Changes in assets and liabilities net of effects of acquisitions	(484,088)	568,293	55,190	2	139,397
Net cash provided by (used in) continuing operations	(807,571)	488,885	220,471	142,081	43,866
Net cash provided by discontinued operations		22,286			22,286
Net cash provided by (used in) operating activities	(807,571)	511,171	220,471	142,081	66,152
Net cash provided by (used in) continuing investing activities	598,884	73,738	(3,642)	(779,263)	(110,283)
Net cash used in discontinued investing activities		(15,143)			(15,143)
Net cash provided by (used in) investing activities	598,884	58,595	(3,642)	(779,263)	(125,426)
Net cash provided by (used in) financing activities	208,687	(402,304)	(234,878)	637,182	208,687
Net change in cash and cash equivalents		167,462	(18,049)		149,413
Cash and cash equivalents, beginning of period	7	(6,076) 7	18,049		11,980
Cash and cash equivalents, end of period	$ 7	$ 161,386	$	$	$ 161,393

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

NOTE 19 SUBSEQUENT EVENTS

On July 13, 2009, the Partnership sold a natural gas processing facility and a one-third undivided interest in other associated assets located in its Mid-Continent operating segment for approximately $22.6 million in cash. The facility was sold to Penn Virginia Resource Partners, L.P. (NYSE: PVR), who will provide natural gas volumes to the facility and reimburse the Partnership for its proportionate share of the operating expenses. The Partnership will continue to operate the facility. The Partnership used the proceeds from this transaction to reduce outstanding borrowings under its senior secured credit facility.

On July 7, 2009, the Partnership received an additional $2.5 million in cash upon the delivery of audited financial statements for the NOARK system assets to Spectra in connection with the completion of the Partnership s sale of its NOARK gas gathering and interstate pipeline system to Spectra for net proceeds of $292.0 million in cash, net of working capital adjustments (see Note 4).

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 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. 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 June 30, 2009, through our Mid-Continent operations, we own and operate:

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

8,750 miles of active natural gas gathering systems located in Oklahoma, 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 third party pipelines.

As of June 30, 2009, our Appalachia operations are conducted principally through our 49% ownership interest in Laurel Mountain Midstream, LLC (Laurel Mountain see Recent Events), a joint venture which owns and operates a 1,770 mile natural gas gathering system in the Appalachia Basin located in eastern Ohio, western New York, and western Pennsylvania. We also own a 65 mile natural gas gathering system in northeastern Tennessee. Laurel Mountain gathers the majority of the natural gas from wells operated by Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a publicly traded company (NYSE: ATN).

Recent Events

On May 31, 2009, we and subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) completed the formation of the Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), which currently owns and operates our Appalachia Basin natural gas gathering system, excluding our Northern Tennessee operations. To Laurel Mountain, Williams contributed cash of $100.0 million, of which we received approximately $87.8 million, net of working capital adjustments, and a note receivable of $25.5 million. We contributed the Appalachia Basin natural gas gathering system and retained a 49% ownership interest in Laurel Mountain, which includes entitlement to preferred distribution rights relating to all payments on the note receivable. Williams retained the remaining 51% ownership interest in Laurel Mountain. Upon completion of the transaction, we recognized our 49% ownership interest in Laurel Mountain as an investment in joint venture on our consolidated balance sheet at fair value and recognized a gain on sale of $109.9 million, including $79.7 million associated with the remeasurement of our investment in Laurel Mountain to fair value. In addition, Atlas Energy sold to Laurel Mountain two natural gas processing plants and associated pipelines located in Southwestern Pennsylvania for $10.0 million. Upon the completion of the transaction, Laurel Mountain entered into new gas gathering agreements with Atlas Energy which superseded the existing natural gas gathering agreements and omnibus agreement between us and Atlas Energy. Under the new gas gathering agreement, Atlas Energy will be obligated to pay Laurel Mountain all of the gathering fees it collects from its investment drilling 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 new 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. Our ownership interest in Laurel Mountain has been recognized in accordance with the equity method of accounting within our consolidated financial statements. We used the net proceeds from the transaction to reduce borrowings under our senior secured credit facility (see Term Loan and Revolving Credit Facility).

On May 29, 2009, we entered into an amendment to our credit facility agreement which, among other changes:

- increased the applicable margin above adjusted LIBOR, the federal funds rate plus 0.5% or the Wachovia Bank prime rate upon which borrowings under the credit facility bear interest;

- for borrowings under the credit facility that bear interest at LIBOR plus the applicable margin, set a floor for the adjusted LIBOR interest rate of 2.0% per annum;

- increased the maximum ratios of funded debt (as defined in the credit agreement) to consolidated EBITDA (as defined in the credit agreement; the leverage ratio) and interest coverage (as defined in the credit agreement) that the credit facility requires us to maintain;

- instituted a maximum ratio of senior secured debt (as defined in the credit agreement) to consolidated EBITDA (the senior secured leverage ratio) that the credit facility requires us to maintain;

- requires that we pay no cash distributions during the remainder of the year ended December 31, 2009 and allows us to pay cash distributions beginning January 1, 2010 if our senior secured leverage ratio is less than 2.75x and we have minimum liquidity (as defined in the credit agreement) of at least $50.0 million;

- generally limits our annual capital expenditures to $95.0 million for the remainder of fiscal 2009 and $70.0 million each year thereafter;

- permitted us to retain (i) up to $135.0 million of net cash proceeds from dispositions completed in fiscal 2009 for reinvestment in similar replacement assets within 360 days, and (ii) up to $50.0 million of net cash proceeds from dispositions completed in any subsequent fiscal year subject to certain limitations as defined within the credit agreement; and

- instituted a mandatory repayment requirement of the outstanding senior secured term loan from excess cash flow (as defined in the credit agreement) based upon our leverage ratio.

On May 5, 2009, we redeemed the remaining 5,000 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). 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 13, 2009, we converted 5,000 of the Class A Preferred Units held by Sunlight Capital, at Sunlight Capital s option, into 1,465,653 common limited partner units in accordance with the terms of the agreement. 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 agreement. 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 May 4, 2009, we completed the sale of our NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE: SEP) (Spectra) for net proceeds of $292.0 million in cash, net of working capital adjustments. We received an additional $2.5 million in cash in July 2009 upon the delivery of audited financial statements for the NOARK system assets to Spectra. We used the net proceeds from the transaction to reduce borrowings under our senior secured term loan and revolving credit facility (see Term Loan and Revolving Credit Facility). We have recognized the sale of the NOARK system assets as discontinued operations within our consolidated financial statements.

Subsequent Events

On July 13, 2009, we sold a natural gas processing facility and a one-third undivided interest in other associated assets located in our Mid-Continent operating segment for approximately $22.6 million in cash. The facility was sold to Penn Virginia Resource Partners, L.P. (NYSE: PVR), who will provide natural gas volumes to the facility and reimburse us for our proportionate share of the operating expenses. We will continue to operate the facility. We used the proceeds from this transaction to reduce outstanding borrowings under our senior secured credit facility.

On July 7, 2009, we received an additional $2.5 million in cash upon the delivery of audited financial statements for the NOARK system assets to Spectra in connection with the completion of our sale of our NOARK gas gathering and interstate pipeline system to Spectra for net proceeds of $292.0 million in cash, net of working capital adjustments (see Recent Events).

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.

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 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.

Revenue in our Appalachia segment is principally recognized at the time the natural gas is transported through our gathering systems.

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. However, energy market uncertainty has negatively impacted North American drilling activity in the recent past. Lower drilling levels and shut-in wells over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. 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 $0.79 per gallon, $5.00 per mmbtu and $69.54 per barrel for NGLs, natural gas and condensate, respectively, would change our gross margin for the twelve-month period ending June 30, 2010 by approximately $23.4 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.

Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Operating data[1]:				
Appalachia:				
Average throughput volume mcfd[2]	107,428	84,475	103,003	80,054
Mid-Continent:				
Velma system:				
Gathered gas volume mcfd	80,068	65,519	73,050	63,960
Processed gas volume mcfd	77,300	62,148	70,625	61,008
Residue gas volume mcfd	61,354	49,033	55,794	48,086
NGL volume bpd	8,497	6,993	7,770	6,841
Condensate volume bpd	416	296	381	277
Elk City/Sweetwater system:				
Gathered gas volume mcfd	221,192	292,544	237,445	298,961
Processed gas volume mcfd	216,804	229,673	235,258	233,038
Residue gas volume mcfd	196,613	207,859	214,228	210,495
NGL volume bpd	11,581	10,452	11,650	10,565
Condensate volume bpd	337	284	432	324
Chaney Dell system:				
Gathered gas volume mcfd	276,901	284,528	289,889	268,008
Processed gas volume mcfd	219,129	256,835	223,468	252,348
Residue gas volume mcfd	240,518	243,465	248,204	231,830
NGL volume bpd	13,663	13,358	13,674	12,880
Condensate volume bpd	909	855	918	781
Midkiff/Benedum system:				
Gathered gas volume mcfd	161,355	150,157	157,687	146,350
Processed gas volume mcfd	150,111	141,240	148,094	138,947
Residue gas volume mcfd	99,106	96,160	102,155	96,386
NGL volume bpd	20,473	20,830	21,555	20,590
Condensate volume bpd	1,533	1,567	1,163	1,144

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

(2) Includes 100% of the throughput volume of Laurel Mountain, a joint venture in which we have a 49% ownership interest, for the period May 31 June 30, 2009.

Financial Presentation

On May 4, 2009, we completed the sale of our NOARK gas gathering and interstate pipeline system (see Recent Events). As such, we have adjusted the prior period consolidated financial information presented to reflect the amounts related to the operations of the NOARK gas gathering and interstate pipeline system as discontinued operations.

Three Months Ended June 30, 2009 Compared to Three Months Ended June 30, 2008

Revenue. Natural gas and liquids revenue was $176.9 million for the three months ended June 30, 2009, a decrease of $253.4 million from $430.3 million for the comparable prior year period. The decline was primarily attributable to decreases in production revenue from the Chaney Dell system of $98.3 million, the Midkiff/Benedum system of $72.4 million, the Velma system of $42.5 million and the Elk City/Sweetwater system of $39.3 million, which were all impacted principally by significantly lower average commodity prices in comparison to the prior year comparable period. Processed natural gas volume on the Elk City/Sweetwater system averaged 216.8 MMcfd for the three months ended June 30, 2009, a decrease of 5.6% from the comparable prior year period. However, NGL production volume for the Elk City/Sweetwater system was 11,581 bpd, an increase of 10.8% from the comparable prior year period, representing an increase in plant production efficiency. The Midkiff/Benedum system had processed natural gas volume of 150.1 MMcfd for the three months ended June 30, 2009, an increase of 6.3% compared to 141.2 MMcfd for the comparable prior year period. Processed natural gas volume averaged 77.3 MMcfd on the Velma system for the three months ended June 30, 2009, an increase of 24.4% from the comparable prior year period. The Velma system s NGL production volume increased 21.5% from the comparable prior year period to 8,497 bpd. Processed natural gas volume on the Chaney Dell system was 219.1 MMcfd for the three months ended June 30, 2009, a decrease of 14.7% compared to 256.8 MMcfd for the comparable prior year period. However, the Chaney Dell system s NGL production volume increased 2.3% from the comparable prior year period to 13,663 bpd for the three months ended June 30, 2009. 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 11 to the consolidated financial statements in Item 1, Financial Statements .

Transportation, compression and other fee revenue decreased to $10.4 million for the three months ended June 30, 2009 compared with $17.1 million for the comparable prior year period. This $6.7 million decrease was primarily due to a $4.9 million decrease from the Appalachia system and a $1.7 million decrease from the Chaney Dell system. The decrease from the Appalachia system was due to our contribution of the majority of the system to Laurel Mountain, a joint venture in which we have a 49% ownership interest, on May 31, 2009, after which we have recognized our ownership interest in the net income of Laurel Mountain as equity income on the consolidated statements of operations. The decrease from the Chaney Dell system was due to lower fee-based volumes.

Equity income of $0.7 million for the three months ended June 30, 2009 represents our ownership interest in the net income of Laurel Mountain, a joint venture in which we own a 49% interest(see Recent Events), for the period from formation on May 31, 2009 through June 30, 2009.

Gain on asset sale of $109.9 million for the three months ended June 30, 2009 represents the gain recognized on our sale of a 51% ownership interest in our Appalachia natural gas gathering system (see Recent Events).

Other loss, net, including the impact of certain gains and losses recognized on derivatives, was a loss of $15.6 million for the three months ended June 30, 2009, which represents a favorable movement of $298.7 million from the comparable prior year period loss of $314.3 million. This favorable movement was due primarily to a $137.3 million favorable movement in non-cash mark-to-market adjustments on derivatives, the absence in the current year period of $115.8 million of net cash derivative expense related to the early termination of a portion of our derivative contracts during June 2008 (see Note 11 to the consolidated financial statements in Item 1, Financial Statements) and a favorable movement of $53.5 million for non-cash derivative gains related to the early termination of a portion of our derivative contracts, partially offset by a $5.8 million unfavorable movement related to cash settlements on derivatives that were not designated as hedges. The $137.3 million favorable movement in non-cash mark-to-market adjustments on derivatives was due principally to the recognition of a $134.8 million loss during the three months ended June 30, 2008, which was due to an increase in forward crude oil market prices from March 31, 2008 to June 30, 2008 and their unfavorable mark-to-market impact on certain non-hedge derivative contracts we had 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 June 30, 2008 were $140.26 per barrel, an increase of $43.32 per barrel from average forward crude oil market prices at March 31, 2008 of $96.94 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 $129.7 million for the three months ended June 30, 2009 represented a decrease of $220.0 million from the prior year comparable period due primarily to a significant decrease in average commodity prices in comparison to the prior year period. Plant operating expenses of $14.1 million for the three months ended June 30, 2009 represented a decrease of $0.7 million from the prior year comparable period due primarily to a $0.8 million decrease associated with the Chaney Dell system resulting from lower operating and maintenance costs. Transportation and compression expenses increased slightly to $2.8 million for the three months ended June 30, 2009 compared with $2.6 million for the prior year comparable period due to higher Appalachia system operating and maintenance expenses as a result of increased capacity in comparison to the prior year period.

General and administrative expense, including amounts reimbursed to affiliates, decreased $3.1 million to $6.5 million for the three months ended June 30, 2009 compared with $9.6 million for the prior year comparable period. The decrease was primarily related to a $1.0 million decrease in executive management s allocable time devoted to our projects and a $0.8 million decrease in non-cash compensation expense.

Depreciation and amortization increased to $23.0 million for the three months ended June 30, 2009 compared with $20.4 million for the three months ended June 30, 2008 due primarily to our expansion capital expenditures incurred subsequent to June 30, 2008.

Interest expense increased to $26.4 million for the three months ended June 30, 2009 as compared with $19.8 million for the comparable prior year period. This $6.6 million increase was primarily due to a $4.6 million increase in interest expense related to our additional senior notes issued during June 2008 (see Senior Notes), a $1.7 million increase in the amortization of deferred finance costs due principally to accelerated amortization associated with the retirement of a portion of our term loan with the proceeds from the sale of our NOARK system (see Recent Events) and a $1.6 million increase in interest expense associated with outstanding borrowings on our revolving credit facility, partially offset by a $2.5 million decrease in interest expense associated with our senior secured term loan primarily due to the repayment of $370.1 million of indebtedness since June 2008 (see Term Loan and Revolving Credit Facility) and lower unhedged interest rates.

Income from discontinued operations consists of amounts associated with the NOARK gas gathering and interstate pipeline system, which we sold on May 4, 2009 (see Recent Events). Income from discontinued operations increased to $53.6 million for the three months ended June 30, 2009 compared with $8.2 million for the comparable prior year period. The increase was due to the $51.1 million gain recognized on the sale of the NOARK system, partially offset by a $5.7 million decrease in the operating results of the NOARK system due to the sale of the system on May 4, 2009.

Income attributable to non-controlling interests decreased $2.4 million to a net income reduction of $0.7 million for the three months ended June 30, 2009 compared with $3.1 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.

Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Revenue. Natural gas and liquids revenue was $332.0 million for the six months ended June 30, 2009, a decrease of $457.9 million from $789.9 million for the comparable prior year period. The decline was primarily attributable to decreases in production revenue from the Chaney Dell system of $168.1 million, the Midkiff/Benedum system of $127.9 million, the Elk City/Sweetwater system of $82.3 million and the Velma system of $78.1 million, which were all impacted principally by significantly lower average commodity prices in comparison to the prior year comparable period. Processed natural gas volume on the Elk City/Sweetwater system averaged 235.3 MMcfd for the six months ended June 30, 2009, an increase of 1.0% from the comparable prior year period. However, NGL production volume for the Elk City/Sweetwater system was 11,650 bpd, an increase of 10.3% from the comparable prior year period, representing an increase in plant production efficiency. The Midkiff/Benedum system had processed natural gas volume of 148.1 MMcfd for the six months ended June 30, 2009, an increase of 6.6% compared to 138.9 MMcfd for the comparable prior year period. NGL production volume for the Midkiff/Benedum system was 21,555 bpd, an increase of 4.7% from the comparable prior year period. Processed natural gas volume averaged 70.6 MMcfd on the Velma system for the six months ended June 30, 2009, an increase of 15.8% from the comparable prior year period. The Velma system s NGL production volume increased 13.6% from the comparable prior year period to 7,770 bpd. Processed natural gas volume on the Chaney Dell system was 223.5 MMcfd for the six months ended June 30, 2009, a decrease of 11.4% compared to 252.3 MMcfd for the comparable prior year period. However, the Chaney Dell system s NGL production volume increased 6.2% from the comparable prior year period to 13,674 bpd for the six months ended June 30, 2009. 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 11 to the consolidated financial statements in Item 1, Financial Statements .

Transportation, compression and other fee revenue decreased to $24.4 million for the six months ended June 30, 2009 compared with $31.2 million for the comparable prior year period. This $6.8 million decrease was primarily due to a $3.8 million decrease from the Appalachia system and a $3.1 million decrease from the Chaney Dell system. The decrease from the Appalachia system was due to our contribution of the majority of the system to Laurel Mountain, a joint venture in which we have a 49% ownership interest, on May 31, 2009, after which we have recognized our ownership interest in the net income of Laurel Mountain as equity income on the consolidated statements of operations. The decrease from the Chaney Dell system was due to lower fee-based volumes.

Equity income of $0.7 million for the six months ended June 30, 2009 represents our ownership interest in the net income of Laurel Mountain, a joint venture in which we own a 49% interest (see Recent Events), for the period from formation on May 31, 2009 through June 30, 2009.

Gain on asset sale of $109.9 million for the six months ended June 30, 2009 represents the gain recognized on our sale of a 51% ownership interest in our Appalachia natural gas gathering system (see Recent Events).

Other loss, net, including the impact of certain gains and losses recognized on derivatives, was a loss of $10.5 million for the six months ended June 30, 2009, which represents a favorable movement of $390.5 million from the comparable prior year period loss of $401.0 million. This favorable movement was due primarily to a $180.0 million favorable movement in non-cash mark-to-market adjustments on derivatives, the absence in the current year period of $115.8 million of net cash derivative expense related to the early termination of a portion of our derivative contracts during June 2008 (see Note 11 to the consolidated financial statements in Item 1, Financial Statements), a favorable movement of $65.6 million for non-cash derivative gains related to the early termination of a portion of our derivative contracts and a $33.5 million favorable movement related to cash settlements on derivatives that were not designated as hedges. The $180.0 million favorable movement in non-cash mark-to-market adjustments on derivatives was due principally to the recognition of a $211.7 million loss during the six months ended June 30, 2008, which was due to an increase in forward crude oil market prices from December 31, 2007 to June 30, 2008 and their unfavorable mark-to-market impact on certain non-hedge derivative contracts we had 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 June 30, 2008 were $140.26 per barrel, an increase of $50.37 per barrel from average forward crude oil market prices at December 31, 2007 of $89.89 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 $264.4 million for the six months ended June 30, 2009 represented a decrease of $359.1 million from the prior year comparable period due primarily to a significant decrease in average commodity prices in comparison to the prior year period. Plant operating expenses of $28.0 million for the six months ended June 30, 2009 represented a decrease of $1.8 million from the prior year comparable period due primarily to a $1.4 million decrease associated with the Midkiff/Benedum system resulting from lower operating and maintenance costs. Transportation and compression expenses increased slightly to $6.1 million for the six months ended June 30, 2009 compared with $5.0 million for the prior year comparable period due to higher Appalachia system operating and maintenance expenses as a result of increased capacity in comparison to the prior year period.

General and administrative expense, including amounts reimbursed to affiliates, increased $2.5 million to $17.2 million for the six months ended June 30, 2009 compared with $14.7 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 of 2009 for the termination of certain positions within our Mid-Continent segment and a $1.9 million increase in non-cash compensation expense, partially offset by lower costs of managing our operations. The increase in non-cash compensation expense was due to a $1.6 million net gain recognized during the six months ended June 30, 2008 principally associated with the vesting of certain common unit awards that were based on the financial performance of certain assets during 2008. These common unit awards were issued during the six months ended June 30, 2009.

Depreciation and amortization increased to $45.7 million for the six months ended June 30, 2009 compared with $40.5 million for the six months ended June 30, 2008 due primarily to our expansion capital expenditures incurred subsequent to June 30, 2008.

Interest expense increased to $47.5 million for the six months ended June 30, 2009 as compared with $40.6 million for the comparable prior year period. This $6.9 million increase was primarily due to a $9.5 million increase in interest expense related to our additional senior notes issued during June 2008 (see Senior Notes), a $2.0 million increase in the amortization of deferred finance costs due principally to accelerated amortization associated with the retirement of a portion of our term loan with the proceeds from the sale of our NOARK system (see Recent Events) and a $2.0 million increase in interest expense associated with outstanding borrowings on our revolving credit facility, partially offset by a $7.4 million decrease in interest expense associated with our senior secured term loan primarily due to the repayment of $370.1 million of indebtedness since June 2008 (see Term Loan and Revolving Credit Facility) and lower unhedged interest rates.

Income from discontinued operations consists of amounts associated with the NOARK gas gathering and interstate pipeline system, which we sold on May 4, 2009 (see Recent Events). Income from discontinued operations increased to $62.5 million for the six months ended June 30, 2009 compared with $14.5 million for the comparable prior year period. The increase was due to the $51.1 million gain recognized on the sale of the NOARK system, partially offset by a $3.1 million decrease in the operating results of the NOARK system due to the sale of the system on May 4, 2009.

Income attributable to non-controlling interests decreased $4.1 million to a net income reduction of $1.1 million for the six months ended June 30, 2009 compared with $5.2 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 June 30, 2009, we had $322.0 million outstanding under our $380.0 million senior secured credit facility and $3.5 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $54.5 million of remaining committed capacity under the credit facility, subject to covenant limitations (see Term Loan and Revolving Credit Facility). We were in compliance with the credit facility s covenants at June 30, 2009. At June 30, 2009, we had a working capital deficit of $55.0 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 $40.4 million increase in net derivative liabilities, a $22.9 million decrease in accounts receivable, and a $4.8 million increase in accrued liabilities, partially offset by a $45.2 million decrease in accounts payable and a $19.8 million decrease in accrued producer liabilities. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash flow. We may need to supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

Recent instability in the financial markets, as a result of recession or otherwise, has increased the cost of capital while the availability of funds from those markets has diminished 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 Six Months Ended June 30, 2009 Compared to Six Months Ended June 30, 2008

Net cash provided by operating activities of continuing operations of $26.6 million for the six months ended June 30, 2009 represented a decrease of $17.3 million from $43.9 million for the prior year comparable period. The decrease was derived principally by a $135.6 million decrease in cash flows from working capital changes, partially offset by a $112.1 million favorable movement in net earnings from continuing operations excluding non-cash charges. The increase in net earnings excluding non-cash charges was principally due to the absence in the current year period of $115.8 million of net cash derivative expense related to the early termination of a portion of our derivative contracts during June 2008 (see Note 11 to the consolidated financial statements in Item 1, Financial Statements). Non-cash charges which impacted net earnings from continuing operations excluding non-cash charges include a $168.0 million decrease in non-cash derivative losses and a $109.9 million decrease from the gain on the sale of our Appalachia system assets, partially offset by a $5.2 million increase in depreciation and amortization expense and a $1.9 million increase in non-cash compensation expense. The movement in non-cash derivative losses resulted from decreases in commodity prices during the six months ended June 30, 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 June 30, 2008. The increase in non-cash compensation expense was principally attributable to a $2.8 million non-cash compensation net gain in the first half of 2008 principally associated with the vesting of certain common unit awards based on the financial performance of certain assets during 2008. This gain was attributable to a mark-to-market adjustment for these common unit awards as a 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 provided by operating activities of discontinued operations of $16.9 million for the six months ended June 30, 2009 represented a decrease of $5.0 million from $21.9 million for the prior year comparable period. The decrease was derived principally by an $11.9 million unfavorable movement in net earnings from discontinued operations excluding non-cash charges, partially offset by a $6.9 million increase in cash flows from working capital changes. The unfavorable movement in net earnings from discontinued operations excluding non-cash charges was due primarily to the sale of our NOARK gas gathering and interstate pipeline system on May 4, 2009 (see Recent Events).

Net cash used in continuing investing activities was $45.0 million for the six months ended June 30, 2009, a decrease of $65.3 million from $110.3 million for the prior year comparable period. This decrease was principally due to the net proceeds of $87.8 million received from the sale of our Appalachian system assets and an $11.6 million decrease in capital expenditures, partially offset by a prior year receipt of a $30.2 million cash reimbursement for state sales tax paid on our prior year transaction to acquire the Chaney Dell and Midkiff/Benedum systems and 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 discontinued investing activities was $290.6 million for the six months ended June 30, 2009, an increase of $305.7 million from $15.1 million of cash used in discontinued investing activities for the prior year comparable period. This increase was principally due to the net proceeds of $292.0 million received from the sale of our NOARK gas gathering and interstate pipeline system (see Recent Events), and a $13.5 million decrease in capital expenditures.

Net cash used in financing activities was $289.6 million for the six months ended June 30, 2009, a decrease of $498.3 million from $208.7 million of net cash provided by financing activities for the comparable prior year period. This decrease was principally due to the prior year $257.2 million of net proceeds from the issuance of our common units during June 2008, $244.9 million of net proceeds from the issuance of 8.75% Senior Notes during June 2008 (see Term Loan and Revolving Credit Facility), a $124.5 million increase in repayments of the outstanding principal balance on our term loan, a $15.0 million redemption of our outstanding Class A preferred units held by Sunlight Capital and our $15.0 million preferred unit investment in Atlas Pipeline Holdings II, LLC (see Note 7 under Item 1., Financial Statements), partially offset by a $105.0 million net increase in borrowings under our revolving credit facility and a $59.3 million decrease in cash distributions to common limited partners and the general partner.

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 related to continuing operations, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008(1)	2009(1)	2008(1)
Maintenance capital expenditures	$ 1,557	$ 1,971	$ 2,101	$ 3,486
Expansion capital expenditures	56,742	64,210	128,393	138,568
Total	$ 58,299	$ 66,181	$ 130,494	$ 142,054

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

Expansion capital expenditures decreased to $56.7 million and $128.4 million for the three and six months ended June 30, 2009, respectively, compared with $64.2 million and $138.6 million for the prior year comparable periods. The decrease was 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 six months ended June 30, 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 and six months ended June 30, 2009 when compared with the comparable prior year period was due to fluctuations in the timing of our scheduled maintenance activity. As of June 30, 2009, we are committed to expend approximately $19.2 million on pipeline extensions, compressor station upgrades and processing facility upgrades. Our senior secured credit facility (see Term Loan and Revolving Credit Facility) generally limits our annual capital expenditures to $95.0 million for the remainder of fiscal 2009 and $70.0 million each year thereafter.

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.

On May 29, 2009, we entered into an amendment to our senior secured credit facility (see Term Loan and Revolving Credit Facility) which, among other changes, requires that we pay no cash distributions during the remainder of the year ended December 31, 2009 and allows us to pay cash distributions beginning January 1, 2010 if our senior secured leverage ratio is above certain thresholds and we have minimum liquidity (both as defined in the credit agreement) of at least $50.0 million.

Off Balance Sheet Arrangements

As of June 30, 2009, our off balance sheet arrangements are limited to our letters of credit outstanding of $3.5 million and our commitments to expend approximately $19.2 million on capital projects.

Common Equity Offering

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.

Preferred Units

Class A Preferred Units

In January 2009, we and Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, agreed to amend certain terms of the preferred units certificate of designation for the then-outstanding 30,000 $1,000 par value 12.0% cumulative convertible Class A preferred units of limited partner interests (the Class A Preferred Units), 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 had 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 would have been required to be redeemed in cash, while we had 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. 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, in accordance with the terms of the amended preferred units certificate of designation. On April 13, 2009, we converted 5,000 of the Class A Preferred Units into 1,465,653 common units in accordance with the terms of the amended preferred units certificate of designation. We reclassified $5.0 million from Class A preferred limited partner equity to common limited partner equity within partners capital when these preferred units were converted into common limited partner units. On May 5, 2009, we redeemed the remaining 5,000 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.

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 Revolving Credit Facility

At June 30, 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 June 30, 2009 was 6.8%, and the weighted average interest rate on the outstanding term loan borrowings at June 30, 2009 was 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $3.5 million was outstanding at June 30, 2009. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet.

On May 29, 2009, we entered into an amendment to our credit facility agreement which, among other changes:

- increased the applicable margin above adjusted LIBOR, the federal funds rate plus 0.5% or the Wachovia Bank prime rate upon which borrowings under the credit facility bear interest;

- for borrowings under the credit facility that bear interest at LIBOR plus the applicable margin, set a floor for the adjusted LIBOR interest rate of 2.0% per annum;

- increased the maximum ratios of funded debt (as defined in the credit agreement) to consolidated EBITDA (as defined in the credit agreement; the leverage ratio) and interest coverage (as defined in the credit agreement) that the credit facility requires us to maintain;

- instituted a maximum ratio of senior secured debt (as defined in the credit agreement) to consolidated EBITDA (the senior secured leverage ratio) that the credit facility requires us to maintain;

- requires that we pay no cash distributions during the remainder of the year ended December 31, 2009 and allows us to pay cash distributions beginning January 1, 2010 if our senior secured leverage ratio is less than 2.75x and we have minimum liquidity (as defined in the credit agreement) of at least $50.0 million;

- generally limits our annual capital expenditures to $95.0 million for the remainder of fiscal 2009 and $70.0 million each year thereafter;

- permitted us to retain (i) up to $135.0 million of net cash proceeds from dispositions completed in fiscal 2009 for reinvestment in similar replacement assets within 360 days, and (ii) up to $50.0 million of net cash proceeds from dispositions completed in any subsequent fiscal year subject to certain limitations as defined within the credit agreement; and

- instituted a mandatory repayment requirement of the outstanding senior secured term loan from excess cash flow (as defined in the credit agreement) based upon our leverage ratio.

In June 2008, we entered into an amendment to our credit facility 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 11 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 revolving 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 our investment in the Laurel Mountain joint venture, 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 also unable to borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement. We are in compliance with these covenants as of June 30, 2009.

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 agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. The credit facility requires us to maintain the following ratios:

Fiscal quarter ending:	Maximum Leverage Ratio	Maximum Senior Secured Leverage Ratio	Minimum Interest Coverage Ratio
June 30, 2009	5.50x	3.00x	2.50x
September 30, 2009	6.50x	3.75x	2.50x
December 31, 2009	8.50x	5.25x	1.70x
March 31, 2010	9.25x	5.75x	1.40x
June 30, 2010	8.00x	5.00x	1.65x
September 30, 2010	7.00x	4.25x	1.90x
December 31, 2010	6.00x	3.75x	2.20x
Thereafter	5.00x	3.00x	2.75x

As of June 30, 2009, our leverage ratio was 3.6 to 1.0, our senior secured leverage ratio was 2.2 to 1.0, and our interest coverage ratio was 4.2 to 1.0.

Senior Notes

At June 30, 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 $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with a net $4.1 million of unamortized discount as of June 30, 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). 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.

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 June 30, 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 June 30, 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.

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 11 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 NGL options. Our Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. Our interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for our NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of natural gas, crude oil, and propane prices, and therefore are defined as Level 3. Valuations for our NGL 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 May 2009, the Financial Accounting Standards Board (FASB) issued Statement No. 165, Subsequent Events (SFAS No. 165). SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS No. 165 requires management of a reporting entity to evaluate events or transactions that may occur after the balance sheet date for potential recognition or disclosure in the financial statements and provides guidance for disclosures that an entity should make about those events. SFAS No. 165 is effective for interim or annual financial periods ending after June 15, 2009 and shall be applied prospectively. We adopted the requirements of SFAS No. 165 on June 30, 2009 and it did not have a material impact to our financial position or results of operations or related disclosures. The adoption of SFAS 165 does not change our current practices with respect to evaluating, recording and disclosing subsequent events.

In April 2009, the FASB issued Staff Position 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly (FSP FAS 157-4). FSP FAS 157-4 applies to all fair value measurements and provides additional clarification on estimating fair value when the market activity for an asset has declined significantly. FSP FAS 157-4 also requires an entity to disclose a change in valuation technique and related inputs to the valuation calculation and to quantify its effects, if practicable. FSP FAS 157-4 is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the requirements of FSP FAS 157-4 on April 1, 2009 and its adoption did not have a material impact on our financial position and results of operations.

In April 2009, the FASB issued Staff Position 115-2 and 124-2, Recognition and Presentation of Other-Than-Temporary Impairments (FSP FAS 115-2 and FAS 124-2). FSP FAS 115-2 and FAS 124-2 change existing guidance for determining whether an impairment is other than temporary for debt securities. FSP FAS 115-2 and FAS 124-2 replaces the existing requirement that an entity s management assess it has both the intent and ability to hold an impaired security until recovery with a requirement that management assess that it does not have the intent to sell the security and that it is more likely than not that it will not have to sell the security before recovery of its cost basis. FSP FAS 115-2 and FAS 124-2 also requires that an entity recognize noncredit losses on held-to-maturity debt securities in other comprehensive income and amortize that amount over the remaining life of the security and for the entity to present the total other-than-temporary impairment in the statement of operations with an offset for the amount recognized in other comprehensive income. FSP FAS 115-2 and FAS 124-2 are effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the requirements of FSP FAS 115-2 and FAS 124-2 on April 1, 2009 and its adoption did not have a material impact on our financial position and results of operations.

In April 2009, the FASB issued Staff Position 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP FAS 107-1 and APB 28-1). FSP FAS 107-1 APB 28-1 requires an entity to provide disclosures about fair value of financial instruments in interim financial information. In addition, an entity shall disclose in the body or in the accompanying notes of its summarized financial information for interim reporting periods and in its financial statements for annual reporting periods the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. FSP FAS 107-1 APL 28-1 is effective for interim periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted the requirements of FSP FAS 107-1 APL 28-1 on April 1, 2009 and its adoption did not have a material impact on our financial position and results of operations.

In April 2009, the FASB issued Staff Position 141(R)-1, Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies (FSP 141(R)-1). FSP 141(R)-1 requires that assets acquired and liabilities assumed in a business combination that arise from contingencies be recognized at fair value if fair value can be reasonably estimated. If fair value of such an asset or liability cannot be reasonably estimated, the asset or liability would generally be recognized in accordance with FASB Statement No. 5, Accounting for Contingencies and FASB Interpretation No. 14, Reasonable Estimation of the Amount of a Loss . FSP 141(R)-1 also eliminates the requirement to disclose an estimate of the range of outcomes of recognized contingencies at the acquisition date. FSP FAS 141(R)-1 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for us). We adopted the requirements of FSP 141(R)-1 on January 1, 2009 and its adoption did not have a material impact on our financial position and results of operations.

In June 2008, the 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 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 11 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. SFAS No. 160 also requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated and adjust its remaining investment, if any, at fair value. 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.

Recently Issued Accounting Standards

In June 2009, the FASB issued Statement No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles A Replacement of FASB Statement No. 162 (SFAS No. 168). SFAS No. 168 establishes the FASB Accounting Standards Codification (Codification) as the single source of authoritative U.S. generally accepted accounting principles recognized by the FASB to be applied by nongovernmental entities. The Codification supersedes all existing non-Securities and Exchange Commission accounting and reporting standards. Following SFAS No. 168, the FASB will not issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, the FASB will issue Accounting Standards Updates, which will serve only to update the Codification. SFAS No. 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We will apply the requirements of SFAS No. 168 to our financial statements for the interim period ending September 30, 2009 and we do not expect it to have a material impact to our financial position or results of operations or related disclosures.

In June 2009, the FASB issued Statement No. 167, Amendments to FASB Interpretation No. 46(R) (SFAS No. 167). SFAS No. 167 is a revision to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities and changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. SFAS No. 167 requires a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. A reporting entity will be required to disclose how its involvement with a variable interest entity affects the reporting entity s financial statements. SFAS No. 167 is effective at the start of a reporting entity s first fiscal year beginning after November 15, 2009 (January 1, 2010 for us). We will apply the requirements of SFAS No. 167 upon its adoption on January 1, 2010 and we do not expect it to have a material impact to our financial position or results of operations or related disclosures.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in interest rates and oil and natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than trading.

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and 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 June 30, 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 June 30, 2009, we had a $380.0 million senior secured revolving credit facility ($322.0 million outstanding). We also had $459.9 million outstanding under our senior secured term loan at June 30, 2009. Borrowings under the credit facility bear interest, at our option at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). On May 29, 2009, we entered into an amendment to our senior secured revolving credit facility agreement which, among other changes, set a floor for the LIBOR interest rate of 2.0% per annum. The weighted average interest rate for the revolving credit facility borrowings was 6.8% at June 30, 2009, and the weighted average interest rate for the term loan borrowings was 6.8% at June 30, 2009.

At June 30, 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. The interest rate swap agreements are in effect as of June 30, 2009 and expire during periods ranging from January 30, 2010 through April 30, 2010. Beginning May 29, 2009, we discontinued hedge accounting for our interest rate derivatives which were qualified as hedges under SFAS No. 133. As such, subsequent changes in fair value of these derivatives will be recognized immediately within other loss, net in our consolidated statements of operations.

Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by $4.5 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based on estimated unhedged market prices of $0.79 per gallon, $5.00 per mmbtu and $69.54 per barrel for NGLs, natural gas and condensate, respectively, would change our gross margin for the twelve-month period ending June 30, 2010 by approximately $23.4 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 loss, net 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. In addition, beginning May 29, 2009, we discontinued hedge accounting for our existing interest rate 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 loss, net in our consolidated statements of operations. The fair value of these commodity derivative instruments at June 30, 2008 and interest rate derivative instruments at May 29, 2009, which were 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 six months ended June 30, 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 and six months ended June 30, 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			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net cash derivative expense included within other loss, net	$	$ (115,810)	$ (5,000)	$ (115,810)
Net cash derivative expense included within natural gas and liquids revenue		(315)		(315)
Net non-cash derivative income (expense) included within other loss, net	7,117	(46,345)	19,220	(46,345)
Net non-cash derivative expense included within natural gas and liquids	(12,123)		(34,067)	

In addition, at June 30, 2009, $13.4 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 July 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Loss from cash and non-cash settlement of qualifying hedge instruments(1)	$ (7,327)	$ (33,152)	$ (27,502)	$ (50,795)
Gain (loss) from change in market value of non-qualifying derivatives(2)	2,509	(136,736)	(42,481)	(207,932)
Gain (loss) from change in market value of ineffective portion of qualifying derivatives(2)		1,934	10,813	(3,726)
Gain (loss) from cash and non-cash settlement of non-qualifying derivatives(2)	(21,105)	(184,564)	13,390	(196,489)
Loss from cash settlement of interest rate derivatives(3)	(2,962)	(194)	(5,855)	(194)

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

(2) Included within other 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):

	June 30, 2009			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments under SFAS No. 133:				
N/A				
Derivatives not designated as hedging instruments under SFAS No. 133:				
Interest rate contracts			Current portion of derivative liability	$ (8,171)
Commodity contracts	Current portion of derivative asset	$ 1,815		
Commodity contracts	Long-term derivative asset	1,606		
Commodity contracts	Current portion of derivative liability	6,848	Current portion of derivative liability	(56,337)
Commodity contracts	Long-term derivative liability	3,151	Long-term derivative liability	(15,899)
		$ 13,420		$ (80,407)

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

	Three months ended June 30, 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:				
N/A				
Derivatives not designated as hedging instruments under SFAS No. 133:				
Interest rate contracts	$ (2,962)	Interest expense	$	N/A
Commodity contracts(1)	$ (10,894)	Natural gas and liquids revenue	$ (13,381)	Other loss, net
Commodity contracts(2)		N/A	(4,155)	Other loss, net
	$ (13,856)		$ (17,536)	

(1) Hedges previously designated as cash flow hedges

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

	Six months ended June 30, 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:				
N/A				
Derivatives not designated as hedging instruments under SFAS No. 133:				
Interest rate contracts	$ (5,855)	Interest expense	$	N/A
Commodity contracts(1)	$ (26,864)	Natural gas and liquids revenue	$ (22,908)	Other loss, net
Commodity contracts(2)			35,665	Other loss, net
	$ (32,719)		$ 12,757	

(1) Hedges previously designated as cash flow hedges

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

As of June 30, 2009, we had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Interest Fixed-Rate Swap

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	$ (2,480)
				2010	(351)
					$ (2,831)
April 2008- April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2009	$ (3,430)
				2010	(1,910)
					$ (5,340)

Natural Gas Liquids Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[(2)] (in thousands)
2009	11,088,000	$ 0.745	$ (573)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Price [(4)] (per barrel)	Fair Value Asset/(Liability)[(3)] (in thousands)	Option Type
2009	234,000	13,185,000	$ 60.97	$ 1,234	Puts purchased
2009	1,055,400	59,081,820	$ 84.75	(2,622)	Calls sold
2010	486,000	27,356,700	$ 61.24	3,838	Puts purchased
2010	3,127,500	213,088,050	$ 86.20	(22,103)	Calls sold
2010	714,000	45,415,440	$ 132.17	708	Calls purchased[(4)]
2011	606,000	33,145,560	$ 100.70	(4,065)	Calls sold
2011	252,000	13,547,520	$ 133.16	764	Calls purchased[(4)]
2012	450,000	25,893,000	$ 102.71	(3,746)	Calls sold
2012	180,000	9,676,800	$ 134.27	801	Calls purchased[(4)]
				$ (25,191)	

Natural Gas Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)[(5)]	Average Fixed Price (per mmbtu) [(6)]	Fair Value Asset [(3)] (in thousands)
2009	240,000	$ 8.000	$ 866

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)[5]	Average Fixed Price (per mmbtu)[6]	Fair Value Asset [3] (in thousands)
2009	2,460,000	$ (0.558)	$ 27
2010	2,220,000	$(0.607)	124
			$ 151

Natural Gas Purchases Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)[5]	Average Fixed Price (per mmbtu)[6]	Fair Value Liability[3] (in thousands)
2009	5,160,000	$ 8.687	$ (22,156)
2010	4,380,000	$ 8.635	(12,414)
			$ (34,570)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)[5]	Average Fixed Price (per mmbtu)[6]	Fair Value Liability[3] (in thousands)
2009	7,380,000	$ (0.659)	$ (83)
2010	6,600,000	$ (0.590)	(111)
			$ (194)

Ethane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price[4] (per gallon)	Fair Value Liability[1] (in thousands)	Option Type
2009	630,000	$ 0.340	$ (40)	Puts purchased

Propane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price[4] (per gallon)	Fair Value Asset[1] (in thousands)	Option Type
2009	15,498,000	$ 0.767	$ 752	Puts purchased

Isobutane Put Options

Production Period Ended December 31,	Associated NGL Volume	Average Price[4]	Fair Value Asset [1]	Option Type

	(gallons)	(per gallon)	(in thousands)	
2009	1,134,000	$ 0.969	$ 20	Puts purchased

Normal Butane Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price(4) (per gallon)	Fair Value Asset(1) (in thousands)	Option Type
2009	9,324,000	$ 0.964	$ 585	Puts purchased

Natural Gasoline Put Options

Production Period Ended December 31,	Associated NGL Volume (gallons)	Average Price[(4)] (per gallon)	Fair Value Asset[(1)] (in thousands)	Option Type
2009	5,796,000	$ 1.267	$ 358	Puts purchased

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability[(3)] (in thousands)
2009	15,000	$ 62.700	$ (131)

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Crude Price[(4)] (per barrel)	Fair Value Asset(Liability)[(3)] (in thousands)	Option Type
2009	231,000	$ 63.017	$ 1,100	Puts purchased
2009	153,000	$ 84.881	(434)	Calls sold
2010	174,000	$ 61.111	1,361	Puts purchased
2010	234,000	$ 88.088	(1,557)	Calls sold
2011	72,000	$ 93.109	(699)	Calls sold
2012	48,000	$ 90.314	(620)	Calls sold
			$ (849)	
		Total net liability	$ (66,987)	

(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) Average price of options based upon average strike price adjusted by average premium paid or received.

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

(6) 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 June 30, 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). These matters were previously described in our quarterly report on Form 10-Q for the quarter ended March 31, 2009. Both matters were settled by agreement dated May 19, 2009. The settlement involved a monetary payment by Elk City, but does not require Elk City to purchase the pipeline assets. The amounts Elk City agreed to pay in connection with the settlement do not have a material impact on our financial condition or 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.

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	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 by and among Atlas Pipeline Partners, L.P., Wachovia Bank, National Association and the several guarantors and lenders thereto[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]
10.1(d)	Amendment No. 2 to Revolving Credit and Term Loan Agreement, dated May 29, 2009[16]
10.2	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]
10.3	Registration Rights Agreement dated December 30, 2008, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P. [11]
10.4	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]
10.5	Purchase Option Agreement between Atlas Pipeline Mid-Continent WestTex, LLC and Pioneer Natural Resources USA, Inc. dated July 27, 2007[4]
10.6	Long-Term Incentive Plan[13]
10.7	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[15]
10.8	Employment agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay[15]
10.9	Securities Purchase Agreement dated April 7, 2009, by and between Atlas Pipeline Mid-Continent, LLC and Spectra Energy Partners OLP, LP
10.10(a)	Revolving Credit Agreement among Atlas Pipeline Holdings, L.P., Atlas Pipeline Partners GP, LLC, Wachovia Bank, National Association, and other banks party thereto, dated as of July 26, 2006

10.10(b)	First Amendment to the Revolving Credit Agreement dated June 1, 2009, by and among Atlas Pipeline Holdings, L.P., Atlas Pipeline Partners GP, LLC, Wachovia Bank, National Association and the lenders thereunder(17)
10.11	Atlas Pipeline Holdings II, LLC Limited Liability Company Agreement(17)
10.12	ATN Option Agreement dated as of June 1, 2009, by and among APL Laurel Mountain, LLC, Atlas Pipeline Operating Partnership, L.P. and Atlas Energy Resources, LLC(18)
10.13	Amended and Restated Limited Liability Company Agreement of Laurel Mountain Midstream, LLC dated as of June 1, 2009(18)
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.

(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.

(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.

(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.

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

(15) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2009.

(16) Previously filed as an exhibit to current report on Form 8-K on June 1, 2009.

(17) Previously filed as an exhibit to current report on Form 8-K on June 2, 2009.

(18) Previously filed as an exhibit to current report on Form 8-K on June 5, 2009.

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: August 7, 2009	By: /s/ EUGENE N. DUBAY Chief Executive Officer, President and Managing Board Member of the General Partner
Date: August 7, 2009	By: /s/ MATTHEW A. JONES Matthew A. Jones Chief Financial Officer of the General Partner
Date: August 7, 2009	By: /s/ SEAN P. MCGRATH Sean P. McGrath Chief Accounting Officer of the General Partner