ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 05, 2010
Table of Contents

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, 2010

OR

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

For the transition period from ______ to ______

Commission file number:1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

The number of common units of the registrant outstanding on August 2, 2010 was 53,252,793.

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO QUARTERLY REPORT

ON FORM 10-Q

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

ASSETS	June 30, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 160	$ 1,021
Accounts receivable	61,613	100,721
Current portion of derivative asset	8,872	998
Prepaid expenses and other	15,661	15,404
Total current assets	86,306	118,144
Property, plant and equipment, net	1,679,581	1,684,384
Intangible assets, net	155,313	168,091
Investment in joint venture	134,504	132,990
Long-term portion of derivative asset	513	361
Other assets, net	30,758	33,993
	$ 2,086,975	$ 2,137,963
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 600	$
Accounts payable - affiliates	6,653	2,043
Accounts payable	19,602	22,928
Accrued liabilities	13,855	14,348
Accrued interest payable	2,579	9,652
Current portion of derivative liability	1,019	33,547
Accrued producer liabilities	60,201	66,211
Total current liabilities	104,509	148,729
Long-term portion of derivative liability	4,778	11,126
Long-term debt, less current portion	1,207,760	1,254,183
Other long-term liability	315	398
Commitments and contingencies		
Partners capital:		
Class B preferred limited partner s interest	14,955	14,955
Class C preferred limited partner s interest	8,000	
Common limited partners interests	805,442	787,834
Investment in Class B cumulative preferred member units of Atlas Pipeline Holdings II, LLC (reported as treasury units)	(15,000)	(15,000)

General partner s interest	15,858	15,853
Accumulated other comprehensive loss	(27,757)	(49,190)
	801,498	754,452
Non-controlling interest	(31,885)	(30,925)
Total partners capital	769,613	723,527
	$ 2,086,975	$ 2,137,963

See accompanying notes to consolidated financial statements

3

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenue:				
Natural gas and liquids	$ 230,941	$ 166,436	$ 491,890	$ 310,569
Transportation, processing and other fees affiliates	155	6,429	331	16,497
Transportation, processing and other fees third parties	14,544	14,433	28,623	29,324
Other income (loss), net	10,540	(15,645)	17,109	(10,496)
Total revenue and other income (loss), net	256,180	171,653	537,953	345,894
Costs and expenses:				
Natural gas and liquids	186,796	129,676	393,459	264,421
Plant operating	15,694	14,128	31,228	27,951
Transportation and compression	232	2,791	421	6,122
General and administrative	5,839	6,164	15,258	16,467
Compensation reimbursement affiliates	375	375	750	750
Depreciation and amortization	22,899	22,999	45,645	45,667
Interest	24,582	26,392	51,013	47,500
Total costs and expenses	256,417	202,525	537,774	408,878
Equity income in joint venture	888	710	2,350	710
Gain on asset sale		109,941		109,941
Income from continuing operations	651	79,779	2,529	47,667
Discontinued operations:				
Gain on sale of discontinued operations		51,078		51,078
Earnings from discontinued operations		2,541		11,417
Income from discontinued operations		53,619		62,495
Net income	651	133,398	2,529	110,162
Income attributable to non-controlling interests	(945)	(652)	(2,262)	(1,121)
Preferred unit dividends				(900)
Net income (loss) attributable to common limited partners and the general partner	$ (294)	$ 132,746	$ 267	$ 108,141

Table of Contents

Allocation of net income (loss) attributable to common limited partners and the general partner:								
Common limited partner interest:								
Continuing operations	$	(288)	$	77,537	$	262	$	44,729
Discontinued operations				52,541				61,239
		(288)		130,078		262		105,968
General partner interest:								
Continuing operations		(6)		1,590		5		917
Discontinued operations				1,078				1,256
		(6)		2,668		5		2,173
Net income (loss) attributable to common limited partners and the general partner:								
Continuing operations		(294)		79,127		267		45,646
Discontinued operations				53,619				62,495
	$	(294)	$	132,746	$	267	$	108,141
Net income (loss) attributable to common limited partners per unit:								
Basic:								
Continuing operations	$	(0.01)	$	1.62	$		$	0.95
Discontinued operations				1.11				1.31
	$	(0.01)	$	2.73	$		$	2.26
Diluted:								
Continuing operations	$	(0.01)	$	1.62	$		$	0.95
Discontinued operations Diluted				1.11				1.31
	$	(0.01)	$	2.73	$		$	2.26
Weighted average common limited partner units outstanding:								
Basic		53,214		47,529		53,033		46,755
Diluted		53,214		47,529		53,163		46,755

See accompanying notes to consolidated financial statements

5

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE SIX MONTHS ENDED JUNE 30, 2010

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units			Class B Preferred	Class C Preferred				Class B Preferred Units of Atlas		
	Class B Preferred	Class C Preferred	Common	Limited Partner	Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive (Loss)	Pipeline Holdings II, LLC	Non-controlling Interest	Partners Capital
Balance at January 1, 2010	15,000		50,517,103	$ 14,955	$	$ 787,834	$ 15,853	$ (49,190)	$ (15,000)	$ (30,925)	$ 723,527
Issuance of common limited partner units			2,689,765			15,319					15,319
Issuance of Class C preferred limited partner units		8,000			8,000						8,000
Distributions to non-controlling interests										(3,222)	(3,222)
Issuance of units under incentive plans			10,584								
Unissued units under incentive plans						2,027					2,027
Other comprehensive income								21,433			21,433
Net income						262	5			2,262	2,529
Balance at June 30, 2010	15,000	8,000	53,217,452	$ 14,955	$ 8,000	$ 805,442	$ 15,858	$ (27,757)	$ (15,000)	$ (31,885)	$ 769,613

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 2,529	$ 110,162
Less: Income from discontinued operations		62,495
Net income from continuing operations	2,529	47,667
Adjustments to reconcile net income from continuing operations to net cash provided by operating activities:		
Depreciation and amortization	45,645	45,667
Equity income in joint venture	(2,350)	(710)
Distribution received from joint venture	6,450	164
Gain on asset sale		(109,941)
Non-cash compensation expense	2,027	259
Amortization of deferred finance costs	3,182	4,653
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable, prepaid expenses and other	38,851	20,422
Accounts payable and accrued liabilities	(18,349)	(18,817)
Derivative accounts payable and accounts receivable	(25,469)	33,814
Accounts payable and accounts receivable affiliates	4,610	2,180
Net cash provided by continuing operations	57,126	25,358
Net cash provided by discontinued operations		16,935
Net cash provided by operations	57,126	42,293
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(23,865)	(130,494)
Capital contributions to joint venture	(5,614)	
Net proceeds from asset sale		87,795
Other	102	(2,346)
Net cash used in continuing investing activities	(29,377)	(45,045)
Net cash provided by discontinued investing activities		290,594
Net cash (used in) provided by investing activities	(29,377)	245,549
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	219,000	325,000
Repayments under credit facility	(260,000)	(305,000)
Repayment of debt	(7,660)	(247,295)
Principal payments on capital lease	(270)	
Net proceeds from issuance of common limited partner units	15,319	
Net proceeds from issuance of preferred limited partner units	8,000	4,955

Redemption of Class A preferred units				(15,000)
General partner capital contributions				308
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)
Net distributions (received from) to non-controlling interests		(3,222)		1,280
Other		223		(11,239)
Net cash used in financing activities		(28,610)		(288,340)
Net change in cash and cash equivalents		(861)		(498)
Cash and cash equivalents, beginning of period		1,021		1,445
Cash and cash equivalents, end of period	$	160	$	947

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

JUNE 30, 2010

(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering and processing of natural gas. The Partnership s operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. At June 30, 2010, Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 1.9% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98.1% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 5,754,253 common limited partner units in the Partnership and 15,000 $1,000 par value 12% cumulative Class B preferred limited partner units. At June 30, 2010, the Partnership had 53,217,452 common limited partnership units outstanding, including the 5,754,253 common units held by the General Partner, plus 15,000 $1,000 par value 12% cumulative Class B preferred limited partner units held by the General Partner and 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units held by Atlas Energy, Inc and its affiliates (Atlas Energy), a publicly-traded company (NASDAQ: ATLS) (see Note 6).

On March 31, 2010, the Partnership s limited partnership agreement was amended to provide a temporary waiver of a capital contribution required for the General Partner to maintain its 2.0% general partner interest in the Partnership, relative to the January 2010 issuance of common units for warrants exercised. The General Partner will not be required to make such capital contribution until it has received aggregate distributions from the Partnership, sufficient to fund the required capital contribution. During this waiver period the General Partner s general partner interest will be reduced by approximately 0.1% to 1.9% (see Note 5).

The General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas Energy, at June 30, 2010, owned a 64.3% ownership interest in AHD s common units, and 1,112,000 of the Partnership s common limited partnership units, representing a 2.1% ownership interest in the Partnership, along with 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units (see Note 6).

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

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-Q from the amounts previously presented to reflect the Partnership s January 1, 2010 reclassification of a portion of its income, within its consolidated statements of operations, to Transportation, Processing and Other Fees for fee-based revenues which were previously reported within Natural Gas and Liquids . This reclassification was made in order to provide clarity between the revenue that is commodity based and the revenue that is fee-based.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2009 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K.

Table of Contents

In management s opinion, all adjustments necessary for a fair presentation of the Partnership s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2009. The results of operations for the three and six month periods ended June 30, 2010 may not necessarily be indicative of the results of operations for the full year ending December 31, 2010. Certain amounts in the prior year s consolidated financial statements have been reclassified to conform to the current year presentation.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership s significant accounting policies is included in its audited consolidated financial statements and notes thereto in its annual report on Form 10-K for the year ended December 31, 2009.

Principles of Consolidation and Non-Controlling Interest

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

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

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

Equity Method Investments

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

Use of Estimates

The preparation of the Partnership s consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership s consolidated financial statements, as well as the reported amounts of revenue and expense during the reporting periods. The Partnership s consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depreciation

Table of Contents

and amortization, asset impairment, the fair value of derivative instruments, the probability of forecasted transactions, the allocation of purchase price to the fair value of assets acquired and other items. Actual results could differ from those estimates.

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

Receivables

In evaluating the realizability of its accounts receivable, the Partnership performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by the Partnership s review of its customers credit information. The Partnership extends credit on an unsecured basis to many of its customers. At June 30, 2010 and December 31, 2009, the Partnership recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 7.4% and 5.8% for the three months ended June 30, 2010 and 2009, respectively, and 7.4% and 5.3% for the six months ended June 30, 2010 and 2009, respectively. The amount of interest capitalized was $0.3 million and $0.5 million for the three months ended June 30, 2010 and 2009, respectively, and $0.5 million and $1.9 million for the six months ended June 30, 2010 and 2009, respectively.

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at June 30, 2010 and December 31, 2009 (dollars in thousands):

	June 30, 2010	December 31, 2009	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,810	$ 12,810	8
Customer relationships	222,572	222,572	7 20
	$ 235,382	$ 235,382	
Accumulated Amortization:			
Customer contracts	$ (8,192)	$ (7,397)	
Customer relationships	(71,877)	(59,894)	
	$ (80,069)	$ (67,291)	
Net Carrying Amount:			
Customer contracts	$ 4,618	$ 5,413	
Customer relationships	150,695	162,678	
	$ 155,313	$ 168,091	

The Partnership amortizes intangible assets with finite useful lives over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful

Table of Contents

lives of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence and expected renewals at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition, adjusted for management s estimate of whether these individual relationships will continue in excess or less than the average length. Amortization expense on intangible assets was $6.4 million for both the three month periods ended June 30, 2010 and 2009, and $12.8 million for both the six month periods ended June 30, 2010 and 2009. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2010 to 2012 - $25.6 million per year; 2013 - $24.5 million; 2014 - $20.4 million.

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner s and the preferred unitholder s interests. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its 1.9% interest and incentive distributions to be distributed for the quarter (see Note 7), with a priority allocation of net income to the General Partner s incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner s and limited partners ownership interests.

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

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership s phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plan and incentive compensation agreements (see Note 14), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award s vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. As such, the net income (loss) utilized in the calculation of net income (loss) per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

Table of Contents

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,	
	2010	2009	2010	2009
Continuing operations:				
Net income	$ 651	$ 79,779	$ 2,529	$ 47,667
Income attributable to non-controlling interest	(945)	(652)	(2,262)	(1,121)
Preferred unit dividends				(900)
Net income (loss) attributable to common limited partners and the general partner	(294)	79,127	267	45,646
General partner s actual ownership interest[1]	(6)	1,590	5	917
Net income (loss) attributable to common limited partners	(288)	77,537	262	44,729
Less: Net income attributable to participating securities phantom units[2]		135		96
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$ (288)	$ 77,402	$ 262	$ 44,633
Discontinued operations:				
Net income	$	$ 53,619	$	$ 62,495
Net income attributable to the general partner s ownership interests[1]		1,078		1,256
Net income utilized in the calculation of net income from discontinued operations attributable to common limited partners per unit	$	$ 52,541	$	$ 61,239

(1) General partner ownership interest was 1.9% and 2.0% during the six months ended June 30, 2010 and 2009, respectively (see Note 1).

(2) Net income attributable to common limited partners ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended June 30, 2010, net loss attributable to common limited partners ownership interest is not allocated to approximately 112,000 phantom units because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners by the sum of the weighted average number of common limited partner units outstanding, including participating securities, plus 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 14). The following table sets forth the reconciliation of the Partnership s weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Weighted average number of common limited partner units basic	53,214	47,529	53,033	46,755
Add effect of participating securities phantom units[1]			81	
Add effect of dilutive option incentive awards[2]			49	

Weighted average common limited partner units diluted	53,214	47,529	53,163	46,755

Table of Contents

(1) For the three months ended June 30, 2010, approximately 112,000 phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such phantom units would have been anti-dilutive.
(2) For the three months ended June 30, 2010 and 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. For the six months ended June 30, 2010 and 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.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income (loss), are referred to as other comprehensive income (loss) or OCI and for the Partnership only include changes in the fair value of unsettled derivative contracts which were accounted for as cash flow hedges (see Note 10). 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,	
	2010	2009	2010	2009
Net income	$ 651	$ 133,398	$ 2,529	$ 110,162
Income attributable to non-controlling interests	(945)	(652)	(2,262)	(1,121)
Preferred unit dividends				(900)
Net income (loss) attributable to common limited partners and the general partner	(294)	132,746	267	108,141
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges		(1,006)		(2,298)
Add: adjustment for realized losses reclassified to net income (loss)	10,715	13,856	21,433	32,719
Total other comprehensive income	10,715	12,850	21,433	30,421
Comprehensive income	$ 10,421	$ 145,596	$ 21,700	$ 138,562

Revenue Recognition

The Partnership s revenue primarily consists of the fees earned from its gathering and processing operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced natural gas liquids (NGLs), if any, off of delivery points on its systems. Under other agreements, the Partnership gathers natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with the Partnership s gathering and processing operations, it enters into the following types of contractual relationships with its producers and shippers:

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

Percentage of Proceeds (POP) Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this contract-type, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership effectively owns a percentage of the commodity and revenues are directly correlated to its market value. POP Contracts may include a fee component which is charged to the producer.

13

Table of Contents

Keep-Whole Contracts. These contracts require the Partnership, as the processor and gatherer, to gather or purchase raw natural gas at current market rates. The volume of gas gathered or purchased is based on the measured volume at an agreed upon location (generally at the wellhead). The volume of gas redelivered or sold at the tailgate of the Partnership s processing facility will be lower than the volume purchased at the wellhead primarily due to NGLs extracted when processed through a plant. The Partnership must make up or keep the producer whole for this loss in volume. To offset the make-up obligation, the Partnership retains the NGLs which are extracted and sells them for its own account. Therefore, the Partnership bears the economic risk (the processing margin risk) that (i) the volume of residue gas available for redelivery to the producer may be less than received from the producer; or (ii) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under Keep-Whole agreements is often lower in BTU content and thus, can meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods of margin risk.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is recorded based upon volumetric data from the Partnership s records and management estimates of the related gathering and compression fees which are, in turn, based upon applicable product prices (see -Use of Estimates accounting policy for further description). The Partnership had unbilled revenues at June 30, 2010 and December 31, 2009 of $26.2 million and $65.4 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Recently Adopted Accounting Standards

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

Recently Issued Accounting Standards

In July 2010, the FASB issued Accounting Standards Update 2010-20, Receivables Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses (Update 2010-20). Update 2010-20 provides enhanced disclosure requirements for allowance for credit losses and the credit quality of financing receivables to assist financial statement users in assessing credit risk exposures and evaluating the adequacy of the allowance for credit losses. This amendment requires disclosures on a disaggregated basis that will further facilitate the evaluation of the nature of credit risk inherent in an entity s financing receivables, how the risks are analyzed and assessed in arriving at the allowance for credit losses, and the changes and reasons for such changes in the allowance for credit losses. This amendment also requires disclosure of credit quality indicators, past due information, a roll-forward schedule of the allowance for credit losses, and any modifications to financing receivables. These requirements are effective for interim and annual reporting periods ending on or after December 15, 2010. The Partnership will apply these requirements upon its adoption on December 15, 2010 and does not expect it to have a material impact on its financial position, results of operations or related disclosures.

NOTE 3 INVESTMENT IN JOINT VENTURE

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

The Partnership recognizes its 49% ownership interest in Laurel Mountain as an investment in joint venture on its consolidated balance sheet. The Partnership accounts for its ownership interest in Laurel Mountain under the equity method of accounting, with recognition of its ownership interest in the income of Laurel Mountain as equity income on its consolidated statements of operations. As of June 30, 2010, the Partnership has utilized $8.5 million of the $25.5 million note receivable and paid cash of $5.6 million to make capital contributions to Laurel Mountain.

The following table provides the joint venture s summarized statement of operations for the three and six months ended June 30, 2010 and 2009 and balance sheet data as of June 30, 2010 and December 31, 2009 (in thousands):

	Three Months Ended		Six Months Ended	
	June 30, 2010	June 30, 2009(1)	June 30, 2010	June 30, 2009(1)
Statement of Operations data:				
Total revenue	$ 10,428	$ 3,068	$ 21,512	$ 3,068
Net income	1,446	1,278	4,093	1,278

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

	June 30, 2010	December 31, 2009
Balance Sheet data:		
Current assets	$ 13,871	$ 12,193
Long-term assets	266,490	248,730
Current liabilities	15,496	19,724
Long-term liabilities	9,454	9,555
Net equity	255,411	231,644

NOTE 4 DISCONTINUED OPERATIONS

On May 4, 2009, the Partnership completed the sale of its NOARK gas gathering and interstate pipeline system to Spectra Energy Partners OLP, LP (NYSE:SEP) (Spectra). The Partnership accounted for the earnings of the NOARK system assets as discontinued operations within its consolidated financial statements and recorded a gain of $51.1 million on the sale of the NOARK assets within income from

Table of Contents

discontinued operations on its consolidated statements of operations during 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 (in thousands):

	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Total revenue and other loss, net	$ 5,269	$ 21,274
Total costs and expenses	(2,728)	(9,857)
Income from discontinued operations	$ 2,541	$ 11,417

NOTE 5 COMMON UNIT EQUITY OFFERING

In August 2009, the Partnership sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. The Partnership also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2.0% general partner interest in the Partnership. In addition, the Partnership issued warrants granting investors in its private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units.

On January 7, 2010, the Partnership executed amendments to the warrants originally issued in August 2009. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million to the Partnership. The Partnership utilized the net proceeds from the common unit offering to repay a portion of its indebtedness under its senior secured term loan (see Note 12) and to fund the early termination of certain derivative agreements (see Note 10).

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

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

NOTE 6 PREFERRED UNIT EQUITY OFFERINGS

On June 30, 2010, the Partnership sold 8,000 newly-created 12% Cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units) to Atlas Energy for cash consideration of $1,000 per Class C Preferred Unit (the Face Value). The Partnership plans to use the proceeds from the sale of the Class C Preferred Units for general partnership purposes. The Class C Preferred Units are entitled to 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 Class C Preferred Units are not convertible into common units of the Partnership. The Partnership has the right at any time to redeem some or all of the outstanding Class C Preferred Units (but not less than 2,500 Class C Preferred Units) for cash at an amount equal to the Class C Preferred Face Value being redeemed plus accrued but unpaid dividends.

The sale of the Class C Preferred Units to Atlas Energy was exempt from the registration requirements of the Securities Act of 1933. The Class C Preferred Units are reflected on the Partnership s consolidated balance sheet as Class C preferred limited partners interest within Partners Capital.

NOTE 7 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of its available cash (as defined in its partnership agreement) for that quarter to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and General Partner distributions declared by the Partnership for the period from January 1, 2009 through June 30, 2010 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 13, 2009	December 31, 2008	$ 0.38	$ 17,463	$ 358
May 15, 2009	March 31, 2009	$ 0.15	$ 7,149	$ 147

In accordance with the restrictions in the Partnership s senior secured credit facility, the Partnership did not declare cash distributions for the quarters ended June 30, 2009 through June 30, 2010 (see Note 12).

NOTE 8 PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2010	December 31, 2009	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,684,500	$ 1,658,282	2 40
Rights of way	167,922	167,048	20 40
Buildings	8,920	8,920	40
Furniture and equipment	9,864	9,538	3 7
Other	13,422	12,849	3 10
	1,884,628	1,856,637	
Less accumulated depreciation	(205,047)	(172,253)	
	$ 1,679,581	$ 1,684,384	

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs are expensed as incurred. Major renewals and improvements that extend the useful lives of property are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset s estimated useful life. The Partnership follows the composite method of depreciation and has determined the composite groups to be the major asset classes of its gathering and processing systems. Under the composite depreciation method, any gain or loss upon disposition or retirement of pipeline, gas gathering and processing components, is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership s results of operations.

17

Table of Contents

During the six months ended June 30, 2010, the Partnership entered into capital lease arrangements having obligations of $2.8 million at inception. Leased property and equipment meeting capital lease criteria are capitalized at the original cost of the equipment and are included within property plant and equipment on the Partnership s consolidated balance sheets. Obligations under capital leases are accounted for as current and noncurrent liabilities and are included within debt on the Partnership s consolidated balance sheets. Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets. The Partnership did not enter into any capital lease arrangements during the six months ended June 30, 2009, and had no capital lease obligations as of December 31, 2009.

NOTE 9 OTHER ASSETS

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

	June 30, 2010	December 31, 2009
Deferred finance costs, net of accumulated amortization of $28,496 and $25,314 at June 30, 2010 and December 31, 2009, respectively	$ 24,197	$ 27,331
Long-term pipeline lease prepayment	3,293	3,168
Security deposits	3,268	3,494
	$ 30,758	$ 33,993

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 12). 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). Total amortization expense of deferred finance costs was $1.6 million and $3.7 million for the three months ended June 30, 2010 and 2009, respectively and $3.2 million and $4.7 million for the six months ended June 30, 2010 and 2009, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations. Amortization expense related to deferred finance costs is estimated to be as follows for each of the next five calendar years: 2010 to 2012 - $6.2 million per year; 2013 - $4.4 million; 2014 - $1.7 million.

NOTE 10 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 previously entered into financial swap instruments to hedge certain portions of its floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. Under its swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period.

On July 1, 2008, the Partnership discontinued hedge accounting for certain existing qualified crude oil derivatives, utilized to hedge forecasted NGL production, due to significant ineffectiveness. The Partnership also discontinued hedge accounting for all of its other qualified commodity derivatives for consistency in reporting of all commodity-based derivatives. As such, subsequent changes in fair value of these derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. The fair

Table of Contents

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.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. Premium costs for purchased options are recorded on the Partnership s consolidated balance sheet as the initial value of the options. Changes in the fair value of the options are recognized within other income (loss), net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premium costs are reclassified to realized gain (loss) within other income (loss), net at the time the option expires or is exercised. At June 30, 2010 the Partnership reflected net derivative assets on its consolidated balance sheets of $3.6 million and at December 31, 2009, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $43.3 million. Of the $27.8 million of net loss in accumulated other comprehensive loss within Partners Capital on the Partnership s consolidated balance sheet at June 30, 2010, the Partnership will reclassify $13.0 million of losses to natural gas and liquids revenue on the Partnership s consolidated statements of operations over the next twelve month period. Aggregate losses of $14.8 million will be reclassified to natural gas and liquids revenue on the Partnership s consolidated statements of operations in later periods. At June 30, 2010, no derivative instruments are designated as hedges for hedge accounting purposes.

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

	June 30, 2010	December 31, 2009
Current portion of derivative asset	$ 8,872	$ 998
Long-term derivative asset	513	361
Current portion of derivative liability	(1,019)	(33,547)
Long-term derivative liability	(4,778)	(11,126)
	$ 3,588	$ (43,314)

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

Contract Type	Balance Sheet Location	June 30, 2010	December 31, 2009
Asset Derivatives			
Commodity contracts	Current portion of derivative asset	$ 9,877	$ 1,591
Commodity contracts	Long-term derivative asset	1,259	361
Commodity contracts	Current portion of derivative liability	1,197	6,562
Commodity contracts	Long-term derivative liability	1,710	3,435
		14,043	11,949
Liability Derivatives			
Interest rate contracts	Current portion of derivative liability		(2,247)
Interest rate contracts	Current portion of derivative asset		(593)
Commodity contracts	Current portion of derivative asset	(1,005)	
Commodity contracts	Long-term derivative asset	(746)	
Commodity contracts	Current portion of derivative liability	(2,216)	(37,862)
Commodity contracts	Long-term derivative liability	(6,488)	(14,561)
		(10,455)	(55,263)
Total Derivatives		$ 3,588	$ (43,314)

Table of Contents

As of June 30, 2010, the Partnership had no interest rate derivative contracts. The following table summarizes the Partnership s commodity derivatives, which are not designated for hedge accounting (dollars and volumes in thousands):

Fixed Price Swaps

Production Period	Purchased/ Sold	Commodity	Volumes[2]	Average Fixed Price	Fair Value[1] Asset/ (Liability)
Natural Gas					
2010	Sold	Natural Gas Basis	2,280	$ (0.700)	$ (699)
2010	Purchased	Natural Gas Basis	2,280	(0.705)	711
2011	Sold	Natural Gas Basis	1,920	(0.728)	(764)
2011	Purchased	Natural Gas Basis	1,920	(0.758)	821
2012	Sold	Natural Gas Basis	720	(0.685)	(270)
2012	Purchased	Natural Gas Basis	720	(0.685)	270
Natural Gas Liquids					
2010	Sold	Propane	17,640	1.108	1,757
2010	Sold	Normal Butane	1,890	1.550	365
2010	Sold	Natural Gasoline	1,512	1.925	412
Crude Oil					
2011	Sold	Crude Oil	78	92.870	1,089
Total Fixed Price Swaps					$ 3,692

Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes[2]	Average Strike Price	Fair Value[1] Asset/ (Liability)
Natural Gas						
2010	Purchased[3]	Call	Natural Gas	4,200	$ 6.000	$ (735)
Natural Gas Liquids						
2010	Purchased[3]	Put	Propane	6,048	1.110	(52)
2010	Purchased[3]	Put	Normal Butane	2,772	1.440	(75)
Crude Oil						
2010	Purchased	Put	Crude Oil	324	74.268	1,214
2010	Sold	Call	Crude Oil	546	100.051	(283)
2010	Purchased[4]	Call	Crude Oil	174	120.000	18
2011	Purchased	Put	Crude Oil	420	89.000	6,299
2011	Sold	Call	Crude Oil	678	94.681	(3,405)
2011	Purchased[4]	Call	Crude Oil	252	120.000	387
2012	Sold	Call	Crude Oil	498	95.835	(4,172)
2012	Purchased[4]	Call	Crude Oil	180	120.000	700
Total Options						$ (104)
Total Fair Value						$ 3,588

(1) See Note 11 for discussion on fair value methodology.
(2) Volumes for Natural Gas are stated in MMBTU s. Volumes for NGLs are stated in gallons. Volumes for Crude Oil are stated in barrels.
(3) Liabilities for purchased options are due to deferred premium payments, which will be paid at the time the options are settled.
(4) 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.

During the six months ended June 30, 2010 and 2009, the Partnership made net payments of $25.3 million and $5.0 million, respectively, related to the early termination of derivative contracts. The terminated derivative contracts were to expire at various times through the fourth quarter of 2010.

Table of Contents

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

Gain (Loss) Recognized in Accumulated OCI		**For the Three Months ended June 30,**		**For the Six Months ended June 30,**	
		2010	**2009**	**2010**	**2009**
Contract Type					
Interest rate contracts[1]		$	$ (1,006)	$	$ (2,298)
		$	$ (1,006)	$	$ (2,298)

Gain (Loss) Reclassified from Accumulated OCI into Income					
Contract Type	**Location**				
Interest rate contracts[1]	Interest expense	$ (457)	$ (2,962)	$ (2,242)	$ (5,855)
Commodity contracts[1]	Natural gas and liquids revenue	(10,258)	(10,894)	(19,191)	(26,864)
		$ (10,715)	$ (13,856)	$ (21,433)	$ (32,719)

Gain (Loss) Recognized in Income (Derivatives not designated as hedges)					
Contract Type	**Location**				
Interest rate contracts[1]	Other income (loss), net	$	$	$ (6)	$
Commodity contracts[1]	Natural gas and liquids revenue		3,694		(509)
Commodity contracts[2]	Other income (loss), net	8,022	(18,593)	12,161	(18,277)
		$ 8,022	$ (14,899)	$ 12,155	$ (18,786)

(1) Hedges previously designated as cash flow hedges
(2) Dedesignated cash flow hedges and non-designated hedges

NOTE 11 FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Instruments

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect the Partnership s own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

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

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

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

The Partnership uses a fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 10). At June 30, 2010, all of the Partnership s derivative contracts are defined as

Table of Contents

Level 2, with the exception of the Partnership s NGL fixed price swaps and NGL options. The Partnership s Level 2 commodity derivatives include natural gas and crude oil swaps and options which are calculated based upon observable market data related to the change in price of the underlying commodity. These swaps and options are calculated by utilizing the New York Mercantile Exchange (NYMEX) quoted price for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula. Valuations for the Partnership s NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations, and therefore are defined as Level 3. Valuations for the Partnership s NGL options are based on forward price curves developed by the related financial institutions, and therefore are defined as Level 3.

The following table represents the Partnership s assets and liabilities recorded at fair value as of June 30, 2010 (in thousands):

	Level 1	Level 2	Level 3	Total
Assets				
Commodity swaps	$	$ 2,891	$ 2,534	$ 5,425
Commodity options		8,617		8,617
Total assets		11,508	2,534	14,042
Liabilities				
Commodity swaps		(1,733)		(1,733)
Commodity options		(8,594)	(127)	(8,721)
Total liabilities		(10,327)	(127)	(10,454)
Total derivatives	$	$ 1,181	$ 2,407	$ 3,588

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments for the six months ended June 30, 2010 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Volume(1)	Amount	Volume(1)	Amount	Amount
Balance December 31, 2009		$	43,470	$ 1,268	$ 1,268
New contracts	21,042		8,820		
Cash settlements from unrealized loss(2)(3)			(43,470)	6,381	6,381
Net change in unrealized loss(2)		2,534		(1,267)	1,267
Option premium recognition(3)				(6,509)	(6,509)
Balance June 30, 2010	21,042	$ 2,534	8,820	$ (127)	$ 2,407

(1) Volumes for NGLs are stated in gallons.
(2) Included within other income (loss), net on the Partnership s consolidated statements of operations.
(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

Other Financial Instruments

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

The Partnership s current assets and liabilities on its consolidated balance sheets, other than the derivatives discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature. The estimated fair values of the Partnership s total debt at June 30, 2010 and December 31, 2009, which consists principally of the term loan, the Senior Notes and borrowings under the credit facility, was $1,170.2 million and $1,194.2 million, respectively, compared with the carrying amounts of $1,208.4 million and $1,254.2 million, respectively. The term loan and Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

NOTE 12 DEBT

Total debt consists of the following (in thousands):

	June 30, 2010	December 31, 2009
Revolving credit facility	$ 285,000	$ 326,000
Term loan	425,845	433,505
8.125% Senior notes due 2015	271,900	271,628
8.75% Senior notes due 2018	223,050	223,050
Capital lease obligations	2,565	
Total debt	1,208,360	1,254,183
Less current maturities	600	
Total long-term debt	$ 1,207,760	$ 1,254,183

Cash payments for interest related to debt were $54.4 million and $40.6 million for the six months ended June 30, 2010 and 2009, respectively.

Term Loan and Revolving Credit Facility

At June 30, 2010, the Partnership had a senior secured credit facility with a syndicate of banks which consisted of a $425.8 million term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at the Partnership s option, at either (i) adjusted LIBOR, subject to a floor of 2.0% per annum, plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on both the outstanding revolving credit facility and term loan borrowings at June 30, 2010 was 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $8.1 million was outstanding at June 30, 2010. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet. At June 30, 2010, the Partnership had $86.9 million of remaining committed capacity under its credit facility, subject to covenant limitations.

The Partnership s senior secured credit facility restricts it from paying cash distributions unless its senior secured leverage ratio meets certain thresholds and it has minimum liquidity (both as defined in the credit agreement) of at least $50.0 million. The senior secured leverage ratio requirement was not met for the quarter ending June 30, 2010. Borrowings under the credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, except for the assets owned by Chaney Dell and Midkiff/Benedum joint ventures and Laurel Mountain; and by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is also unable to borrow under its credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement. The Partnership is in compliance with these covenants as of June 30, 2010 and expects to be in compliance in future periods.

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, 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, 2010, the Partnership s leverage ratio was 7.26 to 1.0, its senior secured leverage ratio was 4.30 to 1.0, and its interest coverage ratio was 1.66 to 1.0.

Senior Notes

At June 30, 2010, the Partnership had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with a net $3.6 million of unamortized discount as of June 30, 2010. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, the Partnership may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its credit facility.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. The Partnership is in compliance with these covenants as of June 30, 2010.

NOTE 13 COMMITMENTS AND CONTINGENCIES

The Partnership is a party to various routine legal proceedings arising in 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.

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

NOTE 14 BENEFIT PLANS

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

A phantom unit entitles a grantee to receive a common limited partner unit upon vesting of the phantom unit. In tandem with phantom unit grants, participants may be granted a distribution equivalent right (DER), which is the right to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. Except for phantom units awarded to non-employee managing board members of the General Partner, a committee (the Committee) appointed by the General Partner s managing board determines the vesting period for phantom units.

A unit option entitles a grantee to purchase a common limited partner unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option is equal to the fair market value of the common unit on the date of grant of the option. The Committee shall determine how the exercise price may be paid by the grantee. The Committee will determine the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant.

Partnership s Long-Term Incentive Plans

The Partnership has a 2004 Long-Term Incentive Plan (2004 LTIP) and a 2010 Long-Term Incentive Plan (2010 LTIP and collectively with the 2004 LTIP, the LTIPs), in which officers, employees, non-employee managing board members of the General Partner, employees of the General Partner s affiliates, and consultants are eligible to participate. The LTIPs are administered by the Committee. On June 15, 2010, the Partnership s unitholders approved the terms of the 2010 LTIP, which provides for the grant of options, phantom units, unit awards, unit appreciation rights and distribution equivalent rights (DERs). Under the 2010 LTIP, the Committee may make awards of either phantom units or unit options for an aggregate of 3,000,000 common units, in addition to the 435,000 common units authorized in the 2004 LTIP. At June 30, 2010, the Partnership had 703,774 phantom units and unit options outstanding under the Partnership s LTIPs, with 2,504,459 phantom units and unit options available for grant.

Through June 30, 2010, phantom units granted under the LTIPs generally had vesting periods of four years. In conjunction with the approval of the 2010 LTIP, the holders of 300,000 of the 375,000 equity indexed bonus units (Bonus Units), under the Partnership s subsidiary s plan discussed below, agreed to exchange their Bonus Units for an equivalent number of phantom units, effective as of June 1, 2010. These phantom units will vest over a two year period, with the first tranche vesting on June 1, 2010. 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. At June 30, 2010, there were 193,685 units outstanding under the LTIPs that will vest within the following twelve months. All phantom units outstanding under the LTIPs at June 30, 2010 include DERs granted to the participants by the Committee. The amounts paid with respect to LTIP DERs were $11,000 and $0.1 million for the three months and six months ended June 30, 2009, respectively. These amounts were recorded as a reduction of Partners capital on the Partnership s consolidated balance sheet. No DERs were paid for the six months ended June 30, 2010.

Table of Contents

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of period	49,163	$ 38.85	101,929	$ 42.58	52,233	$ 39.72	126,565	$ 44.22
Granted	562,500	10.35	500	5.20	563,500	10.35	2,000	4.75
Matured[(1)]	(7,889)	43.15	(25,208)	47.02	(10,584)	43.05	(35,094)	47.22
Forfeited			(500)	43.05	(1,375)	43.99	(16,750)	48.50
Outstanding, end of period[(2)]	603,774	$ 12.24	76,721	$ 40.88	603,774	$ 12.24	76,721	$ 40.88
Non-cash compensation expense recognized (in thousands)[(3)]		$ 1,903		$ 351		$ 2,025		$ 256

(1) The intrinsic values for phantom unit awards exercised during the three months ended June 30, 2010 and 2009 were $0.1 million and $0.1 million, respectively, and $0.1 million and $0.2 million during the six months ended June 30, 2010 and 2009, respectively.

(2) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2010 was $5.9 million.

(3) Non-cash compensation expense includes $1.8 million related to Bonus Units converted to phantom units during the three and six months ended June 30, 2010.

At June 30, 2010, the Partnership had approximately $3.6 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards.

Through June 30, 2010, unit options granted under the Partnership s LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. Awards will automatically vest upon a change of control of the Partnership, as defined in the Partnership s LTIPs. There are 25,000 unit options outstanding under the Partnership s LTIPs at June 30, 2010 that will vest within the following twelve months.

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

	Three Months Ended June 30,			
	2010		2009	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	100,000	$ 6.24	100,000	$ 6.24
Granted				
Matured				
Forfeited				
Outstanding, end of period[(1)(2)]	100,000	$ 6.24	100,000	$ 6.24
Options exercisable, end of period[(1)(3)]	25,000	$ 6.24		

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

26

Table of Contents

	Six Months Ended June 30, 2010		2009	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	100,000	$ 6.24		$
Granted			100,000	6.24
Matured				
Forfeited				
Outstanding, end of period(1)(2)	100,000	$ 6.24	100,000	$ 6.24
Options exercisable, end of period(1)(3)	25,000	$ 6.24		
Weighted average fair value of unit options per unit granted during the period		$	100,000	$ 0.14
Non-cash compensation expense recognized (in thousands)	$ 2		$ 4	

(1) The weighted average remaining contractual life for outstanding and exercisable options at June 30, 2010 was 8.5 years.
(2) The aggregate intrinsic value of options outstanding at June 30, 2010 was $0.3 million.
(3) There were no options exercised during the six months ended June 30, 2010 and 2009.

At June 30, 2010, the Partnership had approximately $5,000 of unrecognized compensation expense related to unvested unit options outstanding under the Partnership s LTIPs 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:

	Six Months Ended June 30, 2009
Expected dividend yield	11.0%
Expected stock price volatility	20.0%
Risk-free interest rate	2.2%
Expected term (in years)	6.3

Employee Incentive Compensation Plan and Agreement

A wholly-owned subsidiary of the Partnership has an incentive plan (the Cash Plan) which allows for equity-indexed cash incentive awards to employees of the Partnership (the Participants), but expressly excludes as an eligible Participant any person that, at the time of the grant, is a Named Executive Officer of the Partnership (as such term is defined under the rules of the Securities and Exchange Commission). The Cash Plan is administered by a committee appointed by the chief executive officer of the Partnership. Under the Cash Plan, cash bonus units may be awarded to Participants at the discretion of the committee, which granted 325,000 bonus units during 2009. In addition, the subsidiary granted an award of 50,000 bonus units to an executive officer on substantially the same terms as the bonus units available under the Cash Plan (the bonus units issued under the Cash Plan and under the separate agreement are, for purposes hereof, referred to as Bonus Units). A Bonus Unit entitles the employee to receive the cash equivalent of the then-fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vest ratably over a three year period from the date of grant and will automatically vest upon a change of control, death, or termination without cause, each as defined in the governing document. Vesting will terminate upon termination of employment with cause. In conjunction with the approval of the 2010 LTIP, the holders of 300,000 of the 375,000 Bonus Units outstanding at June 16, 2010 agreed to exchange their Bonus Units for phantom units, effective as of June 1, 2010.

Table of Contents

A total of 25,000 of the remaining 75,000 Bonus Units vested on June 1, 2010 and an additional 25,000 Bonus Units will vest within the following twelve months. The Partnership recognized compensation expense related to these awards based upon the fair value, which is re-measured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized a credit of $0.3 million and $1.0 million of compensation expense within general and administrative expense on its consolidated statements of operations in the three and six months ended June 30, 2010, respectively, related to the re-measurement of the outstanding Bonus Units during these periods. The Partnership had $0.5 million and $1.2 million, at June 30, 2010 and December 31, 2009, respectively, included within accrued liabilities on its consolidated balance sheet with regard to these awards, which represents their fair value as of those dates.

NOTE 15 RELATED PARTY TRANSACTIONS

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

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $0.4 million for both the three months ended June 30, 2010 and 2009, and $0.8 million for both the six months ended June 30, 2010 and 2009, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the six months ended June 30, 2010 and 2009. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

NOTE 16 SEGMENT INFORMATION

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

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

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

Table of Contents

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

	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Three Months Ended June 30, 2010:				
Revenue:				
Revenues third party[1]	$ 87	$ 258,174	$ (2,236)	$ 256,025
Revenues affiliates	155			155
Total revenue and other income (loss), net	242	258,174	(2,236)	256,180
Costs and Expenses:				
Operating costs and expenses	232	202,490		202,722
General and administrative[2]			6,214	6,214
Depreciation and amortization	150	22,749		22,899
Interest expense[2]			24,582	24,582
Total costs and expenses	382	225,239	30,796	256,417
Equity income	888			888
Net income (loss)	$ 748	$ 32,935	$ (33,032)	$ 651
Three Months Ended June 30, 2009:				
Revenue:				
Revenues third party[1]	$ 772	$ 190,275	$ (25,823)	$ 165,224
Revenues affiliates	6,429			6,429
Total revenue and other income (loss), net	7,201	190,275	(25,823)	171,653
Costs and expenses:				
Operating costs and expenses	2,872	143,723		146,595
General and administrative[2]			6,539	6,539
Depreciation and amortization	1,380	21,619		22,999
Interest expense[2]			26,392	26,392
Total costs and expenses	4,252	165,342	32,931	202,525
Equity income	710			710
Gain on sale of assets	109,941			109,941
Net income (loss) from continuing operation	113,600	24,933	(58,754)	79,779
Income from discontinued operations			53,619	53,619
Net income (loss)	$ 113,600	$ 24,933	$ (5,135)	$ 133,398
Six Months Ended June 30, 2010:				
Revenue:				
Revenues third party[1]	$ 111	$ 544,547	$ (7,036)	$ 537,622
Revenues affiliates	331			331

Total revenue and other income (loss), net	442	544,547	(7,036)	537,953
Costs and Expenses:				
Operating costs and expenses	421	424,687		425,108
General and administrative(2)			16,008	16,008
Depreciation and amortization	301	45,344		45,645
Interest expense(2)			51,013	51,013
Total costs and expenses	722	470,031	67,021	537,774
Equity income	2,350			2,350
Net income (loss)	$ 2,070	$ 74,516	$ (74,057)	$ 2,529

	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Six Months Ended June 30, 2009:				
Revenue:				
Revenues third party[1]	$ 1,597	$ 373,480	$ (45,680)	$ 329,397
Revenues affiliates	16,497			16,497
Total revenue and other income (loss), net	18,094	373,480	(45,680)	345,894
Costs and expenses:				
Operating costs and expenses	6,392	292,102		298,494
General and administrative[2]			17,217	17,217
Depreciation and amortization	3,299	42,368		45,667
Interest expense[2]			47,500	47,500
Total costs and expenses	9,691	334,470	64,717	408,878
Equity income	710			710
Gain on sale of assets	109,941			109,941
Net income (loss) from continuing operation	119,054	39,010	(110,397)	47,667
Income from discontinued operations			62,495	62,495
Net income (loss)	$ 119,054	$ 39,010	$ (47,902)	$ 110,162

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

Capital Expenditures:	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Mid-Continent	$ 15,786	$ 53,842	$ 26,700	$ 120,791
Appalachia		4,457		9,703
	$ 15,786	$ 58,299	$ 26,700	$ 130,494

	June 30, 2010	December 31, 2009
Balance Sheet		
Total assets:		
Mid-Continent	$ 1,908,405	$ 1,964,858
Appalachia	144,988	143,601
Corporate other	33,582	29,504
	$ 2,086,975	$ 2,137,963

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009[1]	2010	2009[1]
Natural gas and liquids:				
Natural gas	$ 72,305	$ 57,922	$ 162,975	$ 134,498
NGLs	146,108	98,228	306,810	164,522
Condensate	13,272	8,539	23,027	9,333
Other	(744)	1,747	(922)	2,216
Total	$ 230,941	$ 166,436	$ 491,890	$ 310,569

(1) Restated to reflect amount reclassified from Natural Gas and Liquids to Transportation, Processing and other fees (see Note 1).

Table of Contents

NOTE 17 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, 2010 and December 31, 2009 and for the three and six months ended June 30, 2010 and 2009 include the financial statements of Atlas Pipeline Mid-Continent WestOk, LLC (Chaney Dell LLC) and Atlas Pipeline Mid-Continent WestTex, LLC (Midkiff/Benedum LLC), entities in which the Partnership has 95% interests. Under the terms of the term loan and revolving credit facility, Chaney Dell LLC and Midkiff/Benedum LLC are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership s stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership s consolidated accounts as of June 30, 2010 and December 31, 2009 and for the three and six months ended June 30, 2010 and 2009. For the purpose of the following financial information, the Partnership s investments in its subsidiaries and the guarantor subsidiaries investments in their subsidiaries are presented in accordance with the equity method of accounting (in thousands):

Balance Sheet	**June 30, 2010**				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$	$ 160	$	$	$ 160
Accounts receivable - affiliates	1,371,611			(1,371,611)	
Current portion of derivative asset		8,872			8,872
Other current assets	15	35,727	41,532		77,274
Total current assets	1,371,626	44,759	41,532	(1,371,611)	86,306
Property, plant and equipment, net		585,114	1,094,467		1,679,581
Notes receivable			1,852,928	(1,852,928)	
Equity investments	581,479	(420,371)		(161,108)	
Investment in joint venture		134,504			134,504
Intangible assets, net		17,383	137,930		155,313
Long-term portion of derivative asset		513			513
Other assets, net	24,197	5,738	823		30,758
	$ 1,977,302	$ 367,640	$ 3,127,680	$ (3,385,647)	$ 2,086,975
Liabilities and Partners Capital (Deficit)					
Accounts payable affiliates	$	$ 1,268,279	$ 109,985	$ (1,371,611)	$ 6,653
Current portion of derivative liability		1,019			1,019
Other current liabilities	1,894	21,659	73,284		96,837
Total current liabilities	1,894	1,290,957	183,269	(1,371,611)	104,509
Long-term derivative liability		4,778			4,778
Long-term debt, less current portion	1,205,795	1,325	640		1,207,760
Other long-term liability		315			315
Partners capital (deficit)	769,613	(929,735)	2,943,771	(2,014,036)	769,613
	$ 1,977,302	$ 367,640	$ 3,127,680	$ (3,385,647)	$ 2,086,975

31

Table of Contents

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

Statement of Operations	Three Months Ended June 30, 2010				
Total revenue and other income (loss), net	$	$ 97,981	$ 176,279	$ (18,080)	$ 256,180
Total costs and expenses	4,755	(126,751)	(152,501)	18,080	(256,417)
Equity income	(4,840)	24,243		(18,515)	888
Income (loss) from continuing operations	(85)	(4,527)	23,778	(18,515)	651
Income from discontinued operations					
Net income	$ (85)	$ (4,527)	$ 23,778	$ (18,515)	$ 651

Statement of Operations	Three Months Ended June 30, 2009				
Total revenue and other income (loss), net	$	$ (4,026)	$ 190,594	$ (14,915)	$ 171,653
Total costs and expenses	(26,395)	(75,259)	(115,786)	14,915	(202,525)
Equity income (loss)	105,284	21,660		(126,234)	710
Gain on asset sale		109,941			109,941
Income (loss) from continuing operations	78,889	52,316	74,808	(126,234)	79,779
Income from discontinued operations		53,619			53,619

Net income (loss)	$ 78,889	$ 105,935	$ 74,808	$ (126,234)	$ 133,398

Table of Contents

Statement of Operations	Six Months Ended June 30, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income (loss), net	$	$ 186,570	$ 369,826	$ (18,443)	$ 537,953
Total costs and expenses	(21,904)	(218,580)	(315,733)	18,443	(537,774)
Equity income	22,479	55,471		(75,600)	2,350
Income (loss) from continuing operations	575	23,461	54,093	(75,600)	2,529
Income from discontinued operations					
Net income	$ 575	$ 23,461	$ 54,093	$ (75,600)	$ 2,529

Statement of Operations	Six Months Ended June 30, 2009				
Total revenue and other income (loss), net	$	$ 52,040	$ 325,950	$ (32,096)	$ 345,894
Total costs and expenses	(47,529)	(160,124)	(233,321)	32,096	(408,878)
Equity income (loss)	103,197	39,964		(142,451)	710
Gain on asset sale		109,941			109,941
Income (loss) from continuing operations	55,668	41,821	92,629	(142,451)	47,667
Income from discontinued operations		62,495			62,495
Net income (loss)	$ 55,668	$ 104,316	$ 92,629	$ (142,451)	$ 110,162

Statement of Cash Flows	Six Months Ended June 30, 2010				
Net cash provided by (used in) operating activities	$ 41,497	$ (2,108)	$ 124,374	$ (106,637)	$ 57,126
Net cash provided by (used in) investing activities	(13,157)	645,099	(16,116)	(645,203)	(29,377)
Net cash provided by (used in) financing activities	(28,340)	(643,852)	(108,258)	751,840	(28,610)
Net change in cash and cash equivalents		(861)			(861)
Cash and cash equivalents, beginning of period		1,021			1,021
Cash and cash equivalents, end of year	$	$ 160	$	$	$ 160

Statement of Cash Flows	Six Months Ended June 30, 2009				
Net cash provided by (used in) continuing operations	$ 147,714	$ 116,383	$ (9,361)	$ (229,378)	$ 25,358
Net cash provided by discontinued operations		16,935			16,935
Net cash provided by (used in) operating activities	147,714	133,318	(9,361)	(229,378)	42,293
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)	52,835	385,526	(288,340)
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 year	$ 7	$ 940	$	$	$ 947

33

Table of Contents

NOTE 18 SUBSEQUENT EVENTS

On July 27, 2010, the Partnership entered into an agreement with a subsidiary of Enbridge Energy Partners, L.P. (NYSE: EEP) to sell its Elk City and Sweetwater, Oklahoma natural gas gathering systems, the related processing and treating facilities (including the Prentiss treating facility) and the Nine Mile processing plant for $682 million in cash, subject to working capital adjustments. The transaction is expected to close prior to December 31, 2010, pending the satisfaction of customary closing conditions. The Partnership intends to utilize the proceeds from the sale to repay a portion of its indebtedness under its senior secured term loan and revolving credit facility (see Note 12).

Table of Contents

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Forward-Looking Statements

When used in this Form 10-Q, the words believes, anticipates, expects and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 1A, under the caption Risk Factors , in our annual report on Form 10-K for the year ended December 31, 2009. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

General

The following discussion provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with our consolidated financial statements and related notes thereto appearing elsewhere in this report.

Overview

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. We are a leading provider of natural gas gathering services in the Anadarko and Permian Basins located in the southwestern and mid-continent United States and the Appalachian Basin in the northeastern United States. In addition, we are a leading provider of natural gas processing and treating services in Oklahoma and Texas.

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

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

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

Recent Events

On June 15, 2010, our unitholders approved the terms of the 2010 Long Term Incentive Plan (2010 LTIP), which provides for the grant of options, phantom units, unit awards, unit appreciation rights and distribution equivalents. The total number of our common units that may be issued under the 2010 LTIP is 3,000,000 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 14 Benefit Plans).

Table of Contents

On June 30, 2010, we sold 8,000 newly created 12% Cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units) to Atlas Energy for cash consideration of $1,000 per Class C Preferred Unit resulting in total proceeds of $8.0 million (see Preferred Units).

Subsequent Events

On July 27, 2010, we entered into an agreement with a subsidiary of Enbridge Energy Partners, L.P. (NYSE: EEP) to sell our Elk City and Sweetwater, Oklahoma natural gas gathering systems, the related processing and treating facilities (including the Prentiss treating facility) and the Nine Mile processing plant for $682 million in cash, subject to working capital adjustments. The transaction is expected to close prior to December 31, 2010, pending the satisfaction of customary closing conditions. We intend to utilize the proceeds from the sale to repay a portion of our indebtedness under our senior secured term loan and revolving credit facility (see Term Loan and Revolving Credit Facility).

Contractual Revenue Arrangements

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

- the volume of natural gas we gather and process which, in turn, depends upon the number of wells connected to our gathering systems, the amount of natural gas they produce, and the demand for natural gas and NGLs;
- the price of the natural gas we gather and process and the NGLs we recover and sell, which is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States;
- the NGL and British Thermal Unit (BTU) content of the gas that is gathered and processed;
- the contract terms with each producer; and
- the efficiency of our gathering systems and processing plants.

Revenue consists of the fees earned from our gathering and processing operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems and then sell the natural gas and NGLs off of delivery points on our systems. Under other agreements, we gather natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas.

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

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.

36

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

As a result of our Percentage of Proceeds and Keep-Whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas and NGLs (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 2 -Revenue Recognition). 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 based derivative instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. See Item 3. Quantitative and Qualitative Disclosures About Market Risk -Commodity Price Risk for further discussion of commodity price risk.

Currently, there is an extremely significant level of uncertainty in the financial markets. This uncertainty presents additional potential risks to us. These risks include the availability and costs associated with our borrowing capabilities and ability to raise 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.

Table of Contents

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,	
	2010	2009	2010	2009
Operating data[1]:				
Appalachia:				
Laurel Mountain system:				
Average throughput volume mcfd[2]	101,821	98,162	99,200	96,716
Tennessee system				
Average throughput volume mcfd	8,546	9,266	8,577	6,287
Mid-Continent:				
Velma system:				
Gathered gas volume mcfd	79,007	80,068	76,396	73,050
Processed gas volume mcfd	72,629	77,300	71,096	70,625
Residue gas volume mcfd	60,043	61,354	57,923	55,794
NGL volume bpd	8,230	8,497	7,996	7,770
Condensate volume bpd	386	416	431	381
Elk City/Sweetwater system[3]:				
Gathered gas volume mcfd	269,435	221,192	249,397	237,445
Processed gas volume mcfd	231,226	216,804	202,089	235,258
Residue gas volume mcfd	209,607	196,613	192,583	214,228
NGL volume bpd	12,092	11,581	10,752	11,650
Condensate volume bpd	494	337	495	432
Chaney Dell system:				
Gathered gas volume mcfd	223,098	276,901	222,554	289,889
Processed gas volume mcfd	173,096	219,129	189,910	223,468
Residue gas volume mcfd	156,057	240,518	172,120	248,204
NGL volume bpd	9,505	13,663	11,022	13,674
Condensate volume bpd	625	909	691	918
Midkiff/Benedum system:				
Gathered gas volume mcfd	180,960	161,355	169,391	157,687
Processed gas volume mcfd	164,111	150,111	156,639	148,094
Residue gas volume mcfd	105,315	99,106	102,493	102,155
NGL volume bpd	26,609	20,473	25,504	21,555
Condensate volume bpd	1,490	1,533	1,092	1,163

(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.
(3) Gathered gas volume for the Elk City/Sweetwater system includes 36,315 MCFD and 39,946 MCFD transferred from the Chaney Dell system for the three months ended June 2010 and 2009, respectively and 18,517 MCFD and 41,446 MCFD for the six months ended June 2010 and 2009, respectively.

Table of Contents

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009

Revenue. The following table details the revenue changes between the three months ended June 30, 2010 and 2009 (dollars in thousands):

	Three Months Ended June 30,			
	2010	2009	Change	Percent Change
Revenues:				
Natural gas and liquids	$ 230,941	$ 166,436	$ 64,505	38.8%
Transportation, processing and other fee revenue	14,699	20,862	(6,163)	(29.5)%
Other income (loss), net	10,540	(15,645)	26,185	167.4%
Total Revenues	$ 256,180	$ 171,653	$ 84,527	49.2%

Natural gas and liquids revenue was $230.9 million for the three months ended June 30, 2010, an increase of $64.5 million from $166.4 million for the prior year comparable period. The increase was primarily attributable to a favorable price change as a result of higher realized commodity prices, partially offset by lower production volumes at the Elk City and Chaney Dell systems.

The Midkiff/Benedum system s NGL production volume for the three months ended June 30, 2010 was 26,609 BPD, an increase of 30.0% when compared to the prior year period, representing an increase in production efficiency due to the start-up of the new Consolidator plant. Processed natural gas volume averaged 72.6 MMCFD on the Velma system for the three months ended June 30, 2010, a decrease of 6.0% from the prior year period, partially due to the plant being shut in for maintenance for a period of time during the current period. Processed natural gas volume on the Chaney Dell and Elk City systems combined was 404.3 MMCFD for the three months ended June 30, 2010, a decrease of 7.3% compared to 435.9 MMCFD for the prior year. The Chaney Dell and Elk City systems had a combined NGL production volume of 21,597 BPD for the three months ended June 30, 2010, a 14.4% decrease when compared to the prior year period of 25,244 BPD. Decreased volumes for the Chaney Dell and Elk City/Sweetwater systems were a result of downtime at the Chaney Dell facilities for maintenance and a decreased number of well connects over the past year, resulting from lower capital spending.

Transportation, processing and other fee revenue decreased to $14.7 million for the three months ended June 30, 2010 compared with $20.9 million for the prior year period. This $6.2 million decrease was primarily due to a $6.5 million decrease from the Appalachia system as a result of our May 2009 contribution of the majority of the system to Laurel Mountain, a joint venture in which we have a 49% ownership interest. After the contribution, we recognized our ownership interest in the net income of Laurel Mountain as equity income on our consolidated statements of operations.

Other income (loss), net, including the impact of certain gains and losses recognized on derivatives, was a gain of $10.5 million for the three months ended June 30, 2010, which represents a favorable movement of $26.2 million from the prior year period loss of $15.6 million. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3: Quantitative and Qualitative Disclosures About Market Risk.

Table of Contents

Costs and Expenses. The following table details the costs and expenses changes between the three months ended June 30, 2010 and 2009 (dollars in thousands):

	Three Months Ended June 30,			
	2010	**2009**	**Change**	**Percent Change**
Costs and Expenses:				
Natural gas and liquids	$ 186,796	$ 129,676	$ 57,120	44.0%
Plant operating	15,694	14,128	1,566	11.1%
Transportation and compression	232	2,791	(2,559)	(91.7)%
General and administrative	6,214	6,539	(325)	(5.0)%
Depreciation and amortization	22,899	22,999	(100)	(0.4)%
Interest expense	24,582	26,392	(1,810)	(6.9)%
Total Costs and Expenses	$ 256,417	$ 202,525	$ 53,892	26.6%

Natural gas and liquids cost of goods sold of $186.8 million for the three months ended June 30, 2010 represented an increase of $57.1 million from the prior year period due primarily to an increase in average commodity prices partially offset by lower volumes in comparison to the prior year period, as discussed above in revenues. Plant operating expenses of $15.7 million for the three months ended June 30, 2010 represented an increase of $1.6 million from the prior year period partially due to a $0.6 million increase associated with the Velma system related to maintenance and chemical expenses and a $0.5 million increase associated with the Midkiff/Benedum system resulting from higher compressor rentals and labor costs related to the new Consolidator gas plant. Transportation and compression expenses decreased to $0.2 million for the three months ended June 30, 2010 compared with $2.8 million for the prior year period due to our contribution of the Appalachia system to Laurel Mountain.

General and administrative expense, including amounts reimbursed to affiliates, decreased $0.3 million to $6.2 million for the three months ended June 30, 2010 compared with $6.5 million for the prior year period. The decrease was primarily due to a $0.3 million decrease in salaries and wages resulting mainly from a credit to compensation expense related to the fair value of share based awards.

Depreciation and amortization decreased $0.1 million to $22.9 million for the three months ended June 30, 2010. Depreciation in the Mid-Continent segment increased $1.1 million due primarily to expansion capital expenditures incurred subsequent to June 30, 2009, offset by a decrease of $1.2 million in the Appalachia segment due to the sale of assets in the second quarter of 2009.

Interest expense decreased to $24.6 million for the three months ended June 30, 2010 as compared with $26.4 million for the prior year period. This $1.8 million decrease was primarily due to a $2.1 million decrease in amortized deferred finance costs. The decreased amortization of deferred finance costs was due principally to accelerated amortization in the prior year period associated with the retirement of a portion of our term loan with the proceeds from the sale of our NOARK system.

Other income items. The following table details the changes between the three months ended June 30, 2010 and 2009 for other income items (dollars in thousands):

	Three Months Ended June 30,			
	2010	**2009**	**Change**	**Percent Change**
Equity income in joint venture	$ 888	$ 710	$ 178	25.1%
Gain on asset sale		109,941	(109,941)	(100.0)%
Income from discontinued operations		53,619	(53,619)	(100.0)%
Income attributable to non-controlling interests	(945)	(652)	(293)	44.9%

Table of Contents

Equity income of $0.9 million for the three months ended June 30, 2010 represents our ownership interest in the net income of Laurel Mountain and is a 25.1% increase from the prior year period, which only included one month of operation.

Gain on asset sale of $109.9 million from the prior year period is the gain recognized on our contribution of a 51% ownership interest in our Appalachia natural gas gathering system to Laurel Mountain, which closed on May 31, 2009.

Income from discontinued operations consists of amounts associated with the NOARK gas gathering and interstate pipeline system, which was sold in May 2009.

Income attributable to non-controlling interests was $0.9 million for the three months ended June 30, 2010 compared with $0.7 million for the prior year period. This change was primarily due to higher net income for the Midkiff/Benedum joint venture, which was formed to accomplish our acquisition of control of the system. The increase in net income of the Midkiff/Benedum joint venture was principally due to higher gross margins on the sale of commodities, resulting from higher prices and volumes. The non-controlling interest expense represents Anadarko Petroleum Corporation s interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Revenue. The following table details the revenue changes between the six months ended June 30, 2010 and 2009 (dollars in thousands):

	Six Months Ended June 30,			
	2010	2009	Change	Percent Change
Revenues:				
Natural gas and liquids	$ 491,890	$ 310,569	$ 181,321	58.4%
Transportation, processing and other fee revenue	28,954	45,821	(16,867)	(36.8)%
Other income (loss), net	17,109	(10,496)	27,605	263.0%
Total Revenues	$ 537,953	$ 345,894	$ 192,059	55.5%

Natural gas and liquids revenue was $491.9 million for the six months ended June 30, 2010, an increase of $181.3 million from $310.6 million for the prior year comparable period. The increase was primarily attributable to a favorable price change as a result of higher realized commodity prices combined with lower qualified hedge losses, partially offset by lower production volumes at the Elk City and Chaney Dell systems. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3: Quantitative and Qualitative Disclosures About Market Risk.

The Midkiff/Benedum system s NGL production volume for the six months ended June 30, 2010 was 25,504 BPD, an increase of 18.3% when compared to the prior year period, representing an increase in production efficiency, primarily due to the start-up of the new Consolidator plant. Processed natural gas volume averaged 71.1 MMCFD on the Velma system for the six months ended June 30, 2010, an increase of 0.7% from the prior year period. Processed natural gas volume on the Chaney Dell and Elk City systems was 392.0 MMCFD for the six months ended June 30, 2010, a decrease of 14.5% compared to 458.7 MMCFD for the prior year. The Chaney Dell and Elk City systems had NGL production volume of 21,774 BPD for the six months ended June 30, 2010, a 14.0% decrease when compared to the prior year period of 25,324 BPD. Decreased volumes for both the Chaney Dell and Elk City/Sweetwater systems were a result of weather related downtime at the facilities and a decreased number of well connects over the past year, resulting from lower capital spending.

Table of Contents

Transportation, processing and other fee revenue decreased to $29.0 million for the six months ended June 30, 2010 compared with $45.8 million for the prior year period. This $16.8 million decrease was primarily due to a $16.6 million decrease from the Appalachia system as a result of our May 2009 contribution of the majority of the system to Laurel Mountain, a joint venture in which we have a 49% ownership interest. After the contribution, we recognized our ownership interest in the net income of Laurel Mountain as equity income on our consolidated statements of operations.

Other income (loss), net, including the impact of certain gains and losses recognized on derivatives, was a gain of $17.1 million for the six months ended June 30, 2010, which represents a favorable movement of $27.6 million from the prior year period loss of $10.5 million. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3: Quantitative and Qualitative Disclosures About Market Risk.

Costs and Expenses. The following table details the costs and expenses changes between the six months ended June 30, 2010 and 2009 (dollars in thousands):

	Six Months Ended June 30,			
	2010	**2009**	**Change**	**Percent Change**
Costs and Expenses:				
Natural gas and liquids	$ 393,459	$ 264,421	$ 129,038	48.8%
Plant operating	31,228	27,951	3,277	11.7%
Transportation and compression	421	6,122	(5,701)	(93.1)%
General and administrative	16,008	17,217	(1,209)	(7.0)%
Depreciation and amortization	45,645	45,667	(22)	0.0%
Interest expense	51,013	47,500	3,513	7.4%
Total Costs and Expenses	$ 537,774	$ 408,878	$ 128,896	31.5%

Natural gas and liquids cost of goods sold of $393.5 million for the six months ended June 30, 2010 represented an increase of $129.0 million from the prior year period due primarily to an increase in average commodity prices partially offset by lower volumes in comparison to the prior year period, as discussed above in revenues. Plant operating expenses of $31.2 million for the six months ended June 30, 2010 represented an increase of $3.3 million from the prior year period due partially due to a $2.0 million increase associated with the Midkiff/Benedum system resulting from higher compressor rentals and labor costs related to the new Consolidator gas plant. Transportation and compression expenses decreased to $0.4 million for the six months ended June 30, 2010 compared with $6.1 million for the prior year period due to our contribution of the Appalachia system to Laurel Mountain.

General and administrative expense, including amounts reimbursed to affiliates, decreased $1.2 million to $16.0 million for the six months ended June 30, 2010 compared with $17.2 million for the prior year period. The decrease was primarily related to a $0.8 million decrease in salaries and wages resulting mainly from non-recurring severance expense incurred during the prior year period.

Depreciation and amortization decreased $0.1 million to $45.6 million for the six months ended June 30, 2010. Depreciation in the Mid-Continent segment increased $2.9 million due primarily to expansion capital expenditures incurred subsequent to June 30, 2009, offset by a decrease of $3.0 million in the Appalachia segment due to the sale of assets in the second quarter of 2009.

Interest expense increased to $51.0 million for the six months ended June 30, 2010 as compared with $47.5 million for the prior year period. This $3.5 million increase was primarily due to a $2.7 million increase in interest expense associated with our term loan, $1.5 million of lower interest capitalized as a component of capital expenditures and a $0.8 million increase in interest expense associated with outstanding borrowings on our revolving credit facility, offset by $1.4 million lower amortization of deferred finance costs. The higher interest expense on our credit facility and term loan is due to higher weighted average interest rates of 6.8% in the six months ended June 30, 2010 compared to average rates of 3.7% in the prior year period. The lower capitalized interest is a result of fewer capital projects in the current period. The decreased amortization of deferred finance costs was due principally to accelerated amortization in the prior year period associated with the retirement of a portion of our term loan with the proceeds from the sale of our NOARK system.

Other income items. The following table details the changes between the six months ended June 30, 2010 and 2009 for other income items (dollars in thousands):

	Six Months Ended June 30,			
	2010	**2009**	**Change**	**Percent Change**
Equity income in joint venture	$ 2,350	$ 710	$ 1,640	231.0%
Gain on sale of assets		109,941	(109,941)	(100.0)%
Income from discontinued operations		62,495	(62,495)	(100.0)%
Income attributable to non-controlling interests	(2,262)	(1,121)	(1,141)	(101.8)%

Equity income of $2.4 million for the six months ended June 30, 2010 represents our ownership interest in the net income of Laurel Mountain and is an increase of $1.6 million from the prior year period, which only included one month of operations.

Gain on asset sale of $109.9 million from the prior year period is the gain recognized on our contribution of a 51% ownership interest in our Appalachia natural gas gathering system to Laurel Mountain.

Income from discontinued operations consists of amounts associated with the NOARK gas gathering and interstate pipeline system, which was sold in May 2009.

Income attributable to non-controlling interests was $2.3 million for the six months ended June 30, 2010 compared with $1.1 million for the prior year period. This change was primarily due to higher net income for the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to accomplish our acquisition of control of the respective systems. The increase in net income of the Chaney Dell and Midkiff/Benedum joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher prices. The non-controlling interest expense represents Anadarko Petroleum Corporation s 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

Table of Contents

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

At June 30, 2010, we had $285.0 million of outstanding borrowings under our $380.0 million senior secured credit facility and $8.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $86.9 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, 2010. At June 30, 2010, we had a working capital deficit of $18.2 million compared with a $30.6 million working capital deficit at December 31, 2009. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash flow. We may need to supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

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

Cash Flows Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

The following table details the cash flow changes between the six months ended June 30, 2010 and 2009 (dollars in thousands):

	Six Months Ended June 30,			
	2010	**2009**	**Change**	**Percent Change**
Net cash provided by operating activities	$ 57,126	$ 42,293	$ 14,833	35.1%
Net cash provided by (used in) investing activities	(29,377)	245,549	(274,926)	(112.0)%
Net cash used in financing activities	(28,610)	(288,340)	259,730	90.1%
Net change in cash and cash equivalents	$ (861)	$ (498)	$ (363)	72.9%

Net cash provided by operating activities of $57.1 million for the six months ended June 30, 2010 represented an increase of $14.8 million from $42.3 million of net cash provided by operating activities for the prior year period. The increase was derived from a $69.7 million increase in net earnings from continuing operations, excluding non-cash charges, partially offset by a $38.0 million decrease in working capital and a $16.9 million decrease in cash provided by discontinued operations. The $69.7 million increase in net earnings from continuing operations, excluding non-cash charges was primarily due to a $52.3 million favorable gross margin related to the sale of natural gas and liquids, as a result of higher prices. The decrease in working capital was primarily due to an unfavorable variance in derivative cash settlements of $46.8 million partially as a result of $36.8 million favorable derivatives cash settlement in the prior period. See Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 10 .

Net cash used in investing activities was $29.4 million for the six months ended June 30, 2010, a decrease of $274.9 million from $245.5 million of net cash provided by investing activities for the prior year period. This decrease was principally due to the net proceeds of $292.0 million received from the sale of our NOARK gas gathering and interstate pipeline system in the prior year period combined with the $87.8 million received from the sale of our 51% interest in the Appalachia assets in the prior year period, partially offset by a $106.6 million decrease in capital expenditures compared to the prior year period. See further discussion of capital expenditures under Liquidity and Capital Resources - Capital Requirements .

Table of Contents

Net cash used in financing activities was $28.6 million for the six months ended June 30, 2010, a decrease of $259.7 million from $288.3 million of net cash used in financing activities for the prior year period. This decrease was mainly due to a $239.6 million net decrease in the repayments of the outstanding principal balance on our term loan and a $26.3 million decrease in cash distributions to common limited partners and the general partner. The decrease in repayments of the outstanding principal balance on our term loan is due to the retirement of a portion of our term loan with the proceeds from the sale of our NOARK system in the prior year period.

Capital Requirements

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

- maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and

- expansion capital expenditures to acquire complementary assets and to expand the capacity of our existing operations.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Maintenance capital expenditures	$ 3,142	$ 1,557	$ 4,313	$ 2,101
Expansion capital expenditures	12,644	56,742	22,387	128,393
Total	$ 15,786	$ 58,299	$ 26,700	$ 130,494

Expansion capital expenditures decreased to $12.6 million and $22.4 million for the three and six months ended June 30, 2010, respectively, compared with $56.7 million and $128.4 million for the prior year comparable periods due partially to the construction of our Madill to Velma pipeline, our Nine Mile gas plant construction and compressor upgrades in the prior year periods, compounded by a reduction of well connects in the current periods. The increase in maintenance capital expenditures for the three and six months ended June 30, 2010 when compared with the comparable prior year periods was partially due to planned maintenance expense at the Waynoka plant plus fluctuations in the timing of other scheduled maintenance activity. As of June 30, 2010, we have approved expenditures of approximately $34.2 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Partnership Distributions

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

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

Available cash is initially distributed 98.1% to our common limited partners and 1.9% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 1.9% of the aggregate amount of cash being distributed. During July 2007, our General Partner, holder of all of our incentive distribution rights, agreed to allocate up to $3.75 million of its incentive distribution rights per quarter back to us after the General Partner receives the initial $7.0 million of incentive distribution rights per quarter. No incentive distributions were declared for the six months ended June 30, 2010.

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

Off Balance Sheet Arrangements

As of June 30, 2010, our off balance sheet arrangements are limited to our letters of credit, issued under the provisions of our revolving credit facility, totaling $8.1 million. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety and (iii) counterparty support.

Common Equity Offering

In August 2009, we sold 2,689,765 common units in a private placement at an offering price of $6.35 per unit, yielding net proceeds of approximately $16.1 million. We also received a capital contribution from the General Partner of $0.4 million for the General Partner to maintain its 2.0% general partner interest in us. In addition, we issued warrants granting investors in our private placement the right to purchase an additional 2,689,765 common units at a price of $6.35 per unit for a period of two years following the issuance of the original common units. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and revolving credit facility (see -Term Loan and Revolving Credit Facility) and to fund the early termination of certain derivative agreements. See Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 10 .

On January 7, 2010, we executed amendments to the warrants which were originally issued in August 2009. The amendments to the warrants provided that, for the period January 8 through January 12, 2010, the warrant exercise price was lowered to $6.00 per unit from $6.35 per unit. In connection with the amendments, the holders of the warrants exercised all of the warrants for cash, which resulted in net cash proceeds of approximately $15.3 million. We utilized the net proceeds from the common unit offering to repay a portion of our indebtedness under our senior secured term loan and credit facility (see -Term Loan and Credit Facility) and to fund the early termination of certain derivative agreements. See Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 10 .

The common units and warrants sold by us in the August 2009 private placement were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement required us to (a) file a registration statement with the Securities and Exchange Commission for the privately placed common units and those underlying the warrants by September 21, 2009 and (b) cause the registration

Table of Contents

statement to be declared effective by the Securities and Exchange Commission by November 18, 2009. We filed a registration statement with the Securities and Exchange Commission in satisfaction of the registration requirements of the registration rights agreement on September 3, 2009, and the registration statement was declared effective on October 14, 2009.

Preferred Units

On June 30, 2010, we sold 8,000 newly-created 12% Cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units) to Atlas Energy for cash consideration of $1,000 per Class C Preferred Unit (the Face Value), for total proceeds of $8.0 million. We plan to use the proceeds from the sale of the Class C Preferred Units for general partnership purposes. See Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 6 .

Term Loan and Revolving Credit Facility

At June 30, 2010, we had a senior secured credit facility with a syndicate of banks which consisted of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at our option, at either (i) adjusted LIBOR, subject to a floor of 2% per annum, plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rates on the outstanding revolving credit facility and term loan borrowings at June 30, 2010 were 6.8%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $8.1 million was outstanding at June 30, 2010. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet.

Our senior secured credit facility restricts us from paying cash distributions unless our senior secured leverage ratio meets certain thresholds and we have minimum liquidity (both as defined in the credit agreement) of at least $50.0 million. The senior secured leverage ratio requirement for paying cash distributions was not met for the quarter ending June 30, 2010. Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum joint ventures and the Laurel Mountain joint venture. Borrowings are also secured by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are also unable to borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement. We are in compliance with these covenants as of June 30, 2010 and expect to be in compliance in future periods.

The events which constitute an event of default for our credit facility include payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. The credit facility requires us to maintain the following ratios:

Fiscal quarter ending:	Maximum Leverage Ratio	Maximum Senior Secured Leverage Ratio	Minimum Interest Coverage Ratio
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, 2010, our leverage ratio was 7.26 to 1.0, our senior secured leverage ratio was 4.30 to 1.0, and our interest coverage ratio was 1.66 to 1.0.

Senior Notes

At June 30, 2010, we had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with a net $3.6 million of unamortized discount as of June 30, 2010. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, we may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under our credit facility.

Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We are in compliance with these covenants as of June 30, 2010.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within our Annual Report on Form 10-K for the year ended December 31, 2009, and there have been no material changes to these policies through June 30, 2010.

Fair Value of Financial Instruments

We use a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect our own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

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

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

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

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

We use a fair value methodology to value the assets and liabilities for our outstanding derivative contracts (see Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 10). At June 30, 2010, all of our derivative contracts are defined as Level 2, with the exception of our NGL fixed price swaps and NGL options. Our Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. Valuations for our NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations and therefore are defined as Level 3. Valuations for our NGL options are based on forward price curves developed by the related financial institutions, and therefore are defined as Level 3.

Recently Adopted Accounting Standards

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

Recently Issued Accounting Standards

In July 2010, the FASB issued Accounting Standards Update 2010-20, Receivables Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses (Update 2010-20). Update 2010-20 provides enhanced disclosure requirements for allowance for credit losses and the credit quality of financing receivables to assist financial statement users in assessing credit risk exposures and evaluating the adequacy of the allowance for credit losses. This amendment requires disclosures on a disaggregated basis that will further facilitate the evaluation of the nature of credit risk inherent in an entity s financing receivables, how the risks are analyzed and assessed in arriving at the allowance for credit losses, and the changes and reasons for such changes in the allowance for credit losses. This amendment also requires disclosure of credit quality indicators, past due information, a roll-forward schedule of the allowance for credit losses, and any modifications to financing receivables. These requirements are effective for interim and annual reporting periods ending on or after December 15, 2010. We will apply these requirements upon its adoption on December 15, 2010 and do not expect it to have a material impact on our financial position, results of operations or related disclosures.

Table of Contents

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodical use of derivative instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on June 30, 2010. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties to our commodity derivative contracts are banking institutions currently participating in our revolving credit facility. We may choose to do business with counterparties outside of our credit facility in the future. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At June 30, 2010, we had a $380.0 million senior secured revolving credit facility ($285.0 million outstanding). We also had $425.8 million outstanding under our senior secured term loan at June 30, 2010. Borrowings under the credit facility bear interest, at our option at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). On May 29, 2009, we entered into an amendment to our senior secured revolving credit facility agreement which, among other changes, set a floor for the LIBOR interest rate of 2.0% per annum. The weighted average interest rate for both the revolving credit facility and term loan borrowings was 6.8% at June 30, 2010. At June 30, 2010, we had no interest rate derivative contracts. Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would not change our annual interest expense.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. We use a number of different derivative instruments in connection with our commodity price risk management activities. We enter into financial swap and option instruments to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain

Table of Contents

indices for the relevant contract period. See Item 1. Notes to Consolidated Financial Statements (Unaudited) -Note 10 for further discussion of our derivative instruments. Average estimated 2010 market prices for NGLs, natural gas and condensate, based upon New York Mercantile Exchange (NYMEX) forward price curves as of July 1, 2010, are $0.81 per gallon, $5.03 per million BTU and $77.29 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended June 30, 2011 by approximately $17.5 million.

During the six months ended June 30, 2010 and 2009, we made net payments of $25.3 million and $5.0 million, respectively, related to the early termination of derivative contracts. The terminated derivative contracts were to expire at various times through the fourth quarter of 2010. During the three and six months ended June 30, 2010, and 2009, we recognized the following derivative activity related to the early termination of these derivative instruments within our consolidated statements of operations (in thousands):

Early termination of derivative contracts	**For the Three Months Ended June 30,**		**For the Six Months Ended June 30,**	
	2010	**2009**	**2010**	**2009**
Cash paid for early termination	$ (11,945)	$	$ (25,315)	$ (5,000)
Less: Deferred recognition of gain on early termination[(1)]	5,615			
Equity applied to prior period early termination	(8,421)		(8,421)	
Total realized loss at early termination[(2)]	$ (14,751)	$	$ (33,736)	$ (5,000)
Net cash derivative gain included within natural gas and liquids revenue	$ 11,540	$	$ 16,737	$
Net cash derivative expense included within other income (loss), net	(26,291)		(50,473)	(5,000)
Total realized loss at early termination[(2)]	(14,751)		(33,736)	(5,000)
Recognition of deferred hedge loss from prior periods included within natural gas and liquids revenue[(3)]	(15,273)	(12,123)	(30,805)	(34,067)
Recognition of deferred hedge gain from prior periods included within other income (loss), net[(3)]	22,726	7,117	44,810	19,220
Total realized loss from early termination recognized in current period[(2)]	$ (7,298)	$ (5,006)	$ (19,731)	$ (19,847)

(1) Deferred recognition is based upon effective portion of hedges deferred to OCI.
(2) Realized gain (loss) represents the gain/loss recognized when the derivative contract is settled. A portion of realized gain (loss) recognized in other income (loss), net is a reclassification of unrealized gain (loss) previously recognized as a factor of recording the changes in the fair value of the derivatives prior to settlement.
(3) Non-Cash recognition of deferred hedge gain (loss) includes (i) theoretical premiums related to calls sold in conjunction with puts purchased in costless collars in which the puts were sold as part of the equity unwinds in 2008 and (ii) the effective portion of hedges deferred to OCI.

In addition, we will recognize, in our consolidated statement of operations, $4.9 million net income, related to derivative contracts terminated in 2008, during the periods for which the hedged physical transactions are forecasted to be settled, with $0.6 million of income to be recognized during the remainder of the year ending December 31, 2010 and $2.3 million and $2.0 million of income to be recognized during the years ending December 31, 2011 and 2012, respectively.

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 as of June 30, 2010, our disclosure controls and procedures were effective at the reasonable assurance level.

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

Table of Contents

PART II. OTHER INFORMATION

ITEM 1A. RISK FACTORS

There have been no material changes in our risk factors from those disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2009.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Securities Purchase Agreement, dated July 27, 2010, by and among Atlas Pipeline Mid-Continent, LLC, Atlas Pipeline Partners, L.P., Enbridge Pipelines (Texas Gathering) L.P. and Enbridge Energy Partners, L.P.[25]
3.1	Certificate of Limited Partnership[1]
3.2(a)	Second Amended and Restated Agreement of Limited Partnership[2]
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership[3]
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership[4]
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership[5]
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership[6]
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership[9]
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership[11]
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership[21]
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership[22]
3.3	Amended and Restated Certificate of Designation for 12% Cumulative Class B Preferred Units[11]
3.4	Certificate of Designation for 12% Cumulative Class C Preferred Units[22]
4.1	Common unit certificate[1]
4.2	8 $^{1}/8$% Senior Notes Indenture dated December 20, 2005[10]
4.3	8 $^{3}/4$% Senior Notes Indenture dated June 27, 2008[7]
10.1(a)	Revolving Credit and Term Loan Agreement dated July 27, 2007 by and among Atlas Pipeline Partners, L.P., Wachovia Bank, National Association and the several guarantors and lenders hereto[4]
10.1(b)	Amendment No. 1 and Agreement to the Revolving Credit and Term Loan Agreement, dated June 12, 2008[6]
10.1(c)	Increase Joinder dated June 27, 2008[8]
10.1(d)	Amendment No. 2 to Revolving Credit and Term Loan Agreement, dated May 29, 2009 [12]
10.2	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[21]
10.3	Form of Warrant to purchase common units dated August 20, 2009[13]
10.4	Form of First Amendment to Warrant to purchase common units dated January 7, 2010[19]
10.5	Long-Term Incentive Plan[20]
10.6	2010 Long-Term Incentive Plan[23]

10.7	Form of Grant of Phantom Units in Exchange for Bonus Units[(23)]
10.8	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter[(24)]
10.9	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan[(20)]

10.10	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement[20]
10.11	Formation and Exchange Agreement dated March 31, 2009 between Williams Field Services Group, LLC, Williams Laurel Mountain, LLC, Atlas Pipeline Partners, L.P., Atlas Pipeline Operating Partnership, L.P. and APL Laurel Mountain, LLC[14]
10.12	Employment Agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay[14]
10.13	Securities Purchase Agreement dated April 7, 2009, by and between Atlas Pipeline Mid-Continent, LLC and Spectra Energy Partners OLP, LP[15]
10.14	Atlas Pipeline Holdings II, LLC Limited Liability Company Agreement[16]
10.15	ATN Option Agreement dated as of June 1, 2009, by and among APL Laurel Mountain, LLC, Atlas Pipeline Operating Partnership, L.P. and Atlas Energy Resources, LLC[17]
10.16	Amended and Restated Limited Liability Company Agreement of Laurel Mountain Midstream, LLC dated as of June 1, 2009[17]
10.17	Letter Agreement, dated as of August 31, 2009, between Atlas America, Inc. and Eric Kalamaras[18]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(5) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
(6) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
(7) Previously filed as an exhibit to current report on Form 8-K on June 27, 2008.
(8) Previously filed as an exhibit to current report on Form 8-K on July 3, 2008.
(9) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
(10) Previously filed as an exhibit to current report on Form 8-K on December 21, 2005.
(11) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
(12) Previously filed as an exhibit to current report on Form 8-K on June 1, 2009.
(13) Previously filed as an exhibit to current report on Form 8-K on August 20, 2009.
(14) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2009.
(15) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2009.
(16) Previously filed as an exhibit to current report on Form 8-K on June 2, 2009.
(17) Previously filed as an exhibit to current report on Form 8-K on June 5, 2009.
(18) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2009.
(19) Previously filed as an exhibit to current report on Form 8-K on January 8, 2010.
(20) Previously filed as an exhibit to annual report on Form 10-K for the year ended December 31, 2009.
(21) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
(22) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
(23) Previously filed as an exhibit to current report on Form 8-K on June 17, 2010.
(24) Previously filed as an exhibit to current report on Form 8-K on June 23, 2010.
(25) Previously filed as an exhibit to current report on Form 8-K on July 29, 2010.

Table of Contents

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 5, 2010	By: /s/ EUGENE N. DUBAY Eugene N. Dubay Chief Executive Officer, President and Managing Board Member of the General Partner
Date: August 5, 2010	By: /s/ ERIC T. KALAMARAS Eric T. Kalamaras Chief Financial Officer of the General Partner
Date: August 5, 2010	By: /s/ ROBERT W. KARLOVICH, III Robert W. Karlovich, III Chief Accounting Officer of the General Partner