

ATLAS PIPELINE PARTNERS LP

Form 10-Q

May 04, 2007

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**UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q**

(Mark One)

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

For the quarterly period ended March 31, 2007

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.)

311 Rouser 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 No

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

Large accelerated filer Accelerated filer Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes No

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ON FORM 10-Q**

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)
(Unaudited)

ASSETS	March 31, 2007	December 31, 2006
Current assets:		
Cash and cash equivalents	\$ 1,839	\$ 1,795
Accounts receivable affiliates	4,985	7,601
Accounts receivable	50,360	51,192
Current portion of derivative asset		5,437
Prepaid expenses and other	6,024	10,444
Total current assets	63,208	76,469
Property, plant and equipment, net	619,537	607,097
Long-term derivative asset		305
Intangible assets, net	24,927	25,530
Goodwill	63,441	63,441
Other assets, net	13,450	14,042
	\$ 784,563	\$ 786,884
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	\$ 50	\$ 71
Accounts payable	12,490	18,624
Accrued liabilities	12,355	6,410
Current portion of derivative liability	18,108	17,362
Accrued producer liabilities	30,534	32,766
Total current liabilities	73,537	75,233
Long-term derivative liability	9,916	8,505
Long-term debt, less current portion	338,976	324,012

Commitments and contingencies

Partners' capital:

Preferred limited partner's interests	39,880	39,381
Common limited partner's interests	339,276	350,805
General partner's interest	10,685	11,034
Accumulated other comprehensive loss	(27,707)	(22,086)
Total partners' capital	362,134	379,134
	\$ 784,563	\$ 786,884

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per unit data)
(Unaudited)

	Three Months Ended	
	March 31,	
	2007	2006
Revenue:		
Natural gas and liquids	\$ 102,176	\$ 100,477
Transportation and compression affiliates	7,720	7,874
Transportation and compression third parties	9,838	8,777
Other income (loss)	(2,197)	682
 Total revenue and other income (loss)	 117,537	 117,810
 Costs and expenses:		
Natural gas and liquids	87,810	85,892
Plant operating	4,530	3,227
Transportation and compression	3,112	2,076
General and administrative	5,703	4,215
Compensation reimbursement affiliates	630	720
Depreciation and amortization	6,534	5,275
Interest	6,759	6,337
Minority interest in NOARK		569
 Total costs and expenses	 115,078	 108,311
 Net income	 2,459	 9,499
Preferred unit imputed dividend cost	(499)	(95)
 Net income attributable to common limited partners and the general partner	 \$ 1,960	 \$ 9,404
 Allocation of net income attributable to common limited partners and the general partner:		
Common limited partners interest	\$ (1,884)	\$ 5,806
General partner's interest	3,844	3,598
 Net income attributable to common limited partners and the general partner	 \$ 1,960	 \$ 9,404
 Net (loss) income attributable to common limited partners per unit:		
Basic	\$ (0.14)	\$ 0.46
Diluted	\$ (0.14)	\$ 0.46

Weighted average common limited partner units outstanding:

Basic	13,080	12,549
Diluted	13,080	12,687

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
FOR THE THREE MONTHS ENDED MARCH 31, 2007
(in thousands, except unit data)
(Unaudited)

	Number of Limited Partner Units	Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Total Partners Capital	
	Preferred	Common					
Balance at January 1, 2007	40,000	13,080,418	\$ 39,381	\$ 350,805	\$ 11,034	\$ (22,086)	\$ 379,134
Costs incurred related to issuance of common units				(40)			(40)
Unissued common units under incentive plans				1,821			1,821
Costs incurred related to issuance of units under incentive plans				(40)			(40)
Distributions paid to common limited partners and the general partner Distribution				(11,249)	(4,193)		(15,442)
equivalent rights paid on unissued units under incentive plans				(137)			(137)
Other comprehensive loss						(5,621)	(5,621)
Net income			499	(1,884)	3,844		2,459
Balance at March 31, 2007	40,000	13,080,418	\$ 39,880	\$ 339,276	\$ 10,685	\$ (27,707)	\$ 362,134

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Three Months Ended	
	March 31,	
	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	\$ 2,459	\$ 9,499
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	6,534	5,275
Non-cash loss (gain) on derivatives	2,277	(540)
Non-cash compensation expense	1,781	1,319
Amortization of deferred finance costs	534	593
Minority interest in NOARK		569
Change in operating assets and liabilities:		
Accounts receivable and prepaid expenses and other	5,254	(169)
Accounts payable and accrued liabilities	(2,420)	(6,988)
Accounts payable and accounts receivable affiliates	2,616	542
Net cash provided by operating activities	19,035	10,100
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(18,377)	(13,562)
Other	94	(4)
Net cash used in investing activities	(18,283)	(13,566)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	60,500	9,500
Repayments under credit facility	(45,500)	(19,000)
Net proceeds from issuance of preferred limited partner units		29,994
General partner capital contribution		591
Distributions paid to common limited partners and the general partner	(15,442)	(14,054)
Other	(266)	(13)
Net cash (used in) provided by financing activities	(708)	7,018
Net change in cash and cash equivalents	44	3,552
Cash and cash equivalents, beginning of period	1,795	34,237
Cash and cash equivalents, end of period	\$ 1,839	\$ 37,789

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2007
(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the transmission, gathering and processing of natural gas. The Partnership's operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 2% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 1,641,026 limited partner units in the Partnership which have not been registered with the Securities and Exchange Commission and, therefore, their resale in the public market is subject to restrictions under the Securities Act. At March 31, 2007, the Partnership had 13,080,418 common limited partnership units, including 1,641,026 unregistered common units held by the General Partner, and 40,000 \$1,000 par value cumulative convertible preferred limited partnership units outstanding (see Note 4 and Note 15).

The Partnership's General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas America, Inc. and its affiliates (Atlas America), a publicly-traded company (NASDAQ: ATLS), had an 82.9% ownership interest in AHD's outstanding common units at March 31, 2007. Atlas America also had an 80.6% ownership interest in the outstanding common units of Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a publicly-traded company (NYSE: ATN) focused on the development of natural gas and oil in the Appalachian basin. Substantially all of the natural gas the Partnership transports in the Appalachian Basin is derived from wells operated by Atlas Energy.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2006 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management's opinion, all adjustments necessary for a fair presentation of the Partnership's financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2006. The results of operations for the three month period ended March 31, 2007 may not necessarily be indicative of the results of operations for the full year ending December 31, 2007.

Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the current year presentation. During June 2006, the Partnership identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and first quarter of 2006, the Partnership recorded an adjustment of \$1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the \$1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership's

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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, 2006.

Principles of Consolidation and Minority Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership's wholly-owned and majority-owned subsidiaries. The General Partner's interest in the Operating Partnership is reported as part of its overall 2% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

The consolidated financial statements also include the financial statements of NOARK Pipeline System, Limited Partnership (NOARK), an entity in which the Partnership currently owns a 100% ownership interest (see Note 8). In May 2006, the Partnership acquired the remaining 25% ownership interest in NOARK from Southwestern Energy Pipeline Company (Southwestern), a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Prior to this transaction, the Partnership owned a 75% ownership interest in NOARK, which it had acquired in October 2005 from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE). In connection with the acquisition of the remaining 25% ownership interest, Southwestern assumed liability for \$39.0 million in principal amount outstanding of NOARK's 7.15% notes due in 2018, which had been presented as long-term debt on the Partnership's consolidated balance sheet prior to the acquisition of the remaining 25% ownership interest. Subsequent to the acquisition of the remaining 25% ownership interest in NOARK, the Partnership consolidates 100% of NOARK's financial statements. The minority interest expense in NOARK reflected on the Partnership's consolidated statements of income represents Southwestern's interest in NOARK's net income prior to the May 2006 acquisition.

Use of Estimates

The preparation of the Partnership's consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. Actual results could differ from those estimates (see Item 2, Management's Discussion and Analysis for further discussion).

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month's financial results. Management believes that the operating results presented for the three months ended March 31, 2007 represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

Net Income Per Common Unit

Basic net income attributable to common limited partners per unit is computed by dividing net income attributable to common limited partners, which is determined after the deduction of the general partner's and the preferred unitholder's interests, by the weighted average number of common limited partner units outstanding during the period. The general partner's interest in net income is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 5), with a priority allocation of net income in an amount equal to the general partner's incentive distributions, in accordance with the partnership agreement, and the remaining net income or loss allocated with respect to the general partner's and limited partners' ownership interests. Diluted net income attributable to common limited partners per unit is calculated by dividing net income attributable to common limited partners by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of phantom unit awards, as calculated by the treasury stock method. Phantom units consist of common units issuable under the terms of the Partnership's Long-Term Incentive Plan

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and Incentive Compensation Agreements (see Note 12). The following table sets forth the reconciliation of the weighted average number of common limited partner units used to compute basic net income attributable to common limited partners per unit with those used to compute diluted net income attributable to common limited partners per unit (in thousands):

		Three Months Ended March 31,	
		2007	2006
Weighted average number of common limited partner units	basic	13,080	12,549
Add: effect of dilutive unit incentive awards ⁽¹⁾			138
Weighted average number of common limited partner units	diluted	13,080	12,687

- (1) For the three months ended March 31, 2007, approximately 245,000 phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would be antidilutive.

Comprehensive (Loss) Income

Comprehensive (loss) income includes net income or 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, are referred to as other comprehensive (loss) income and for the Partnership only include changes in the fair value of unsettled derivative contracts accounted for as hedges. The following table sets forth the calculation of the Partnership's comprehensive (loss) income (in thousands):

		Three Months Ended March 31,	
		2007	2006
Net income		\$ 2,459	\$ 9,499
Preferred unit imputed dividend cost		(499)	(95)
Net income attributable to common limited partners and the general partner		1,960	9,404

Other comprehensive (loss) income:

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Changes in fair value of derivative instruments accounted for as hedges	(8,668)	374
Add: adjustment for realized losses reclassified to net income	3,047	2,400
Total other comprehensive (loss) income	(5,621)	2,774
Comprehensive (loss) income	\$ (3,661)	\$ 12,178

Revenue Recognition

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

The Partnership's Mid-Continent segment revenue primarily consists of the fees earned from its transmission, gathering and processing operations. Under certain agreements, the Partnership purchases gas

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from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced natural gas liquids (NGLs), if any, off of delivery points on its systems. Under other agreements, the Partnership transports natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the Partnership's regulated transmission pipeline is recognized at the time the transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. The majority of the revenue associated with the Partnership's gathering and processing operations is based on percentage-of-proceeds (POP) and fixed-fee contracts. Under its POP purchasing arrangements, the Partnership purchases natural gas at the wellhead, processes the natural gas by extracting NGLs and removing impurities and sells the residue gas and NGLs at market-based prices, remitting to producers a contractually-determined percentage of the sale proceeds.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Partnership's records and management estimates of the related transportation and compression fees which are, in turn, based upon applicable product prices (see Use of Estimates accounting policy for further description). The Partnership had unbilled revenues at March 31, 2007 and December 31, 2006 of \$10.7 million and \$20.2 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 8.0 % and 8.1% for the three months ended March 31, 2007 and 2006, respectively, and the amount of interest capitalized was \$0.5 million and \$0.3 million for the three months ended March 31, 2007 and 2006, respectively.

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions (see Note 8). The following table reflects the components of intangible assets being amortized at March 31, 2007 and December 31, 2006 (in thousands):

	March 31, 2007	December 31, 2006	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	\$ 12,390	\$ 12,390	8
Customer relationships	17,260	17,260	20
	\$ 29,650	\$ 29,650	
Accumulated Amortization:			
Customer contracts	\$ (3,033)	\$ (2,646)	
Customer relationships	(1,690)	(1,474)	
	\$ (4,723)	\$ (4,120)	
Net Carrying Amount:			
Customer contracts	\$ 9,357	\$ 9,744	
Customer relationships	15,570	15,786	

\$ 24,927 \$ 25,530

During the third quarter of 2006, the Partnership adjusted the preliminary purchase price allocation for
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the NOARK acquisition and reduced the estimated amount allocated to customer contracts and customer relationships based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6).

Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets (SFAS No. 142) requires that intangible assets with finite useful lives be amortized over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership's customer contract intangible assets is based upon the approximate average length of customer contracts in existence 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. Amortization expense on intangible assets was \$0.6 million and \$1.2 million for the three months ended March 31, 2007 and 2006, respectively. Amortization expense related to intangible assets is estimated to be \$2.4 million for each of the next five calendar years commencing in 2007.

Goodwill

At March 31, 2007 and December 31, 2006, the Partnership had \$63.4 million of goodwill recorded in connection with consummated acquisitions (see Note 8). The changes in the carrying amount of goodwill for the three months ended March 31, 2007 and 2006 were as follows (in thousands):

	Three Months Ended March 31,	
	2007	2006
Balance, beginning of period	\$ 63,441	\$ 111,446
Reduction in minority interest deficit acquired NOARK		(569)
Purchase price allocation adjustment NOARK		(245)
Balance, end of period	\$ 63,441	\$ 110,632

During the third quarter of 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to goodwill based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6). The Partnership tests its goodwill for impairment at each year end by comparing enterprise fair values to carrying values. The evaluation of impairment under SFAS No. 142 requires the use of projections, estimates and assumptions as to the future performance of the Partnership's operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections, resulting in revisions to the Partnership's assumptions and, if required, recognition of an impairment loss. The Partnership's test of goodwill at December 31, 2006 resulted in no impairment, and no impairment indicators have been noted as of March 31, 2007. The Partnership will continue to evaluate its goodwill at least annually and if impairment indicators arise, and will reflect the impairment of goodwill, if any, within the consolidated statement of income for the period in which the impairment is indicated.

New Accounting Standards

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The Statement will be effective as of the beginning of an entity's first fiscal year

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beginning after November 15, 2007. The Statement offers various options in electing to apply the provisions of this Statement, and at this time the Partnership has not made any decisions with regards to its application to its financial position or results of operations. The Partnership is currently evaluating whether SFAS No. 159 will have an impact on its financial position and results of operations.

In September 2006, the Financial Accounting Standards Board issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value statements. This statement does not require any new fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Partnership is currently evaluating whether SFAS No. 157 will have an impact on its financial position and results of operations.

NOTE 3 COMMON UNIT EQUITY OFFERING

In May 2006, the Partnership sold 500,000 common units to Wachovia Securities, which then offered the common units to public investors. The units, which were issued under the Partnership's previously filed shelf registration statement, resulted in net proceeds of approximately \$19.7 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale to partially repay borrowings under its credit facility made in connection with its acquisition of the remaining 25% ownership interest in NOARK.

NOTE 4 PREFERRED UNIT EQUITY OFFERING

On March 13, 2006, the Partnership entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC, an affiliate of Elliott & Associates, for aggregate gross proceeds of \$30.0 million. The Partnership also sold an additional 10,000 6.5% cumulative preferred units to Sunlight Capital Partners for \$10.0 million on May 19, 2006, pursuant to the Partnership's right under the agreement to require Sunlight Capital Partners to purchase such additional units. Commencing on March 13, 2007, the preferred units will be entitled to receive dividends of 6.5% per annum, which will accrue and be paid quarterly on the same date as the distribution payment date for the Partnership's common units (see Note 15). The preferred units are convertible, at the holder's option, into the Partnership's common units commencing on the date immediately following the first record date after March 13, 2007 at a conversion price equal to the lesser of \$41.00 or 95% of the market price of the Partnership's common units as of the date of the notice of conversion. The Partnership may elect to pay cash rather than issue common units in satisfaction of a conversion request. The Partnership has the right to call the preferred units at a specified premium. The Partnership has filed a registration statement to cover the resale of the common units underlying the preferred units. The net proceeds from the initial issuance of the preferred units were used to fund a portion of the Partnership's capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under the Partnership's credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK.

The preferred units are reflected on the Partnership's consolidated balance sheet as preferred equity within partners capital. In accordance with Securities and Exchange Commission Staff Accounting Bulletin No. 68, Increasing Rate Preferred Stock, the preferred units were recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. The imputed dividend cost is the result of the preferred units not having a dividend yield during the first year after their issuance on March 13, 2006. The total imputed dividend cost of \$2.4 million on the preferred units was allotted to common limited partners and the general partner's interests within partners capital on the consolidated balance sheet and is based upon the present value of the net proceeds received using the 6.5% stated yield commencing March 13, 2007. The imputed dividend cost is amortized for the period from the respective issuances of the preferred units through March 13, 2007, and the amortization is presented as a reduction of net income to determine net income attributable to common limited partners and the general partner. Amortization of the imputed dividend cost for

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the three months ended March 31, 2007 and 2006 was \$0.5 million and \$0.1 million, respectively. If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership's consolidated balance sheet. Dividends accrued and paid on the preferred units and the premium paid upon their redemption, if any, will be recognized as a reduction to the Partnership's net income in determining net income attributable to common unitholders and the general partner.

NOTE 5 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. If 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. Distributions declared by the Partnership for the period from January 1, 2006 through March 31, 2007 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 14, 2006	December 31, 2005	\$ 0.83	\$10,416	\$ 3,638
May 15, 2006	March 31, 2006	\$ 0.84	\$10,541	\$ 3,766
August 14, 2006	June 30, 2006	\$ 0.85	\$11,118	\$ 4,059
November 14, 2006	September 30, 2006	\$ 0.85	\$11,118	\$ 4,059
February 14, 2007	December 31, 2006	\$ 0.86	\$11,249	\$ 4,193

On April 26, 2007, the Partnership declared a cash distribution of \$0.86 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2007. The \$15.4 million distribution, including \$4.2 million to the General Partner, will be paid on May 15, 2007 to unitholders of record at the close of business on May 8, 2007.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2007	December 31, 2006	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	\$ 629,027	\$ 611,575	15-40
Rights of way	30,983	30,401	20-40
Buildings	3,801	3,800	40
Furniture and equipment	3,430	3,288	3-7
Other	2,243	2,081	3-10
	669,484	651,145	
Less accumulated depreciation	(49,947)	(44,048)	
	\$ 619,537	\$ 607,097	

In May 2006, the Partnership acquired the remaining 25% ownership interest in NOARK for \$69.0 million in cash, including the repayment of the \$39.0 million of NOARK notes at the date of acquisition (see Note 8). The Partnership acquired the initial 75% ownership interest in NOARK for approximately \$179.8 million in October 2005 (see Note 8). During the third quarter of 2006, the Partnership adjusted the preliminary

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purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to customer contracts and customer relationships intangible assets and goodwill based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment.

NOTE 7 OTHER ASSETS

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

	March 31, 2007	December 31, 2006
Deferred finance costs, net of accumulated amortization of \$4,506 and \$3,972 at March 31, 2007 and December 31, 2006, respectively	\$ 12,030	\$ 12,530
Security deposits	1,355	1,415
Other	65	97
	\$ 13,450	\$ 14,042

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 10).

NOTE 8 ACQUISITIONS**NOARK**

In May 2006, the Partnership acquired the remaining 25% ownership interest in NOARK from Southwestern, for a net purchase price of \$65.5 million, consisting of \$69.0 million of cash to the seller (including the repayment of the \$39.0 million of outstanding NOARK notes at the date of acquisition), less the seller's interest in NOARK's working capital (including cash on hand and net payables to the seller) at the date of acquisition of \$3.5 million. In October 2005, the Partnership acquired from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE), all of the outstanding equity of Atlas Arkansas Pipeline, LLC, which owned the initial 75% ownership interest in NOARK, for total consideration of \$179.8 million, including \$16.8 million for working capital adjustments and other related transaction costs. NOARK's assets included a Federal Energy Regulatory Commission (FERC)-regulated interstate pipeline and an unregulated natural gas gathering system. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141, Business Combinations (SFAS No. 141). The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in both acquisitions, based on their fair values at the date of the respective acquisitions (in thousands):

Cash and cash equivalents	\$ 16,215
Accounts receivable	11,091
Prepaid expenses	497
Property, plant and equipment	232,576
Other assets	140
Total assets acquired	260,519
Accounts payable and accrued liabilities	(50,689)
Net assets acquired	209,830
Less: Cash and cash equivalents acquired	(16,215)
Net cash paid for acquisitions	\$ 193,615

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The Partnership's ownership interests in the results of NOARK's operations associated with each acquisition are included within its consolidated financial statements from the respective dates of the acquisitions.

NOTE 9 DERIVATIVE INSTRUMENTS

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. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these 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. Option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133).

The Partnership formally documents all relationships between hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching the commodity futures and derivative contracts to the forecasted transactions. The Partnership assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in offsetting changes in the forecasted cash flow of hedged items. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of correlation between the hedging instrument and the underlying commodity, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by the Partnership through the utilization of market data, will be recognized immediately within other income in its consolidated statements of income.

Derivatives are recorded on the Partnership's consolidated balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value in partners' capital as accumulated other comprehensive (loss) income, and reclassifies them to natural gas and liquids revenue within natural gas and liquids revenue in its consolidated statements of income as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, the Partnership recognizes changes in fair value within other income in its consolidated statements of income as they occur. At March 31, 2007 and December 31, 2006, the Partnership reflected net derivative liabilities on its consolidated balance sheets of \$28.0 million and \$20.1 million, respectively. Of the \$27.7 million of net loss in accumulated other comprehensive loss within partners' capital on the Partnership's consolidated balance sheet at March 31, 2007, if the fair values of the instruments remain at current market values, the Partnership will reclassify \$17.0 million of losses to natural gas and liquids revenue in its consolidated statements of income over the next twelve month period as these contracts expire, and \$10.7 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes. Ineffective hedge gains or losses are recorded within other income in the Partnership's consolidated statements of income while the hedge contracts are open and may increase or decrease until settlement of the contract. The Partnership recognized losses of \$3.0 million and \$2.4 million for the three months ended March 31, 2007 and 2006, respectively, within natural gas and liquids revenue in its consolidated statements of income related to the settlement of qualifying hedge instruments. The Partnership recognized losses of \$1.3 million and \$1.0 million within other income in its consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the three months ended March 31, 2007. The Partnership recognized a gain of \$0.5 million for the three months ended March 31, 2006 within other income in its consolidated statements of income related to the change in market value of the ineffective portion of qualifying derivatives only. For the three months ended March 31, 2006, the Partnership did not have non-qualifying derivatives.

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A portion of the Partnership's future natural gas, NGL and condensate sales is periodically hedged through the use of swaps and collar contracts. Realized gains and losses on the derivative instruments that are classified as effective hedges are reflected in the contract month being hedged as an adjustment to natural gas and liquids revenue within the Partnership's consolidated statements of income.

As of March 31, 2007, the Partnership had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability ⁽¹⁾ (in thousands)
2007	71,631,000	\$ 0.901	\$ (9,221)
2008	33,012,000	0.697	(9,076)
2009	8,568,000	0.746	(2,113)
			\$ (20,410)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability) ⁽²⁾ (in thousands)	Option Type
2008	693,600	38,744,000	\$60.00	\$ 2,526	Puts purchased
2008	693,600	38,744,000	84.00	(2,570)	Calls sold
2009	720,000	40,219,000	60.00	3,314	Puts purchased
2009	720,000	40,219,000	81.00	(1,838)	Calls sold
				\$ 1,432	

Natural Gas Sales

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Liability ⁽²⁾ (in thousands)
2007	810,000	\$ 7.255	\$ (798)
2008	240,000	7.270	(395)
2009	480,000	8.000	(162)
			\$ (1,355)

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Asset ⁽²⁾ (in thousands)
2007	810,000	\$ (0.535)	\$ 362
2008	240,000	(0.555)	150

2009	480,000	(0.540)	50
			\$ 562

Table of Contents**Natural Gas Purchases**

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Liability ⁽²⁾ (in thousands)
2007	5,220,000	\$ 8.854 ⁽⁴⁾	\$ (4,926)
2008	4,056,000	8.719 ⁽⁵⁾	(733)
2009	2,880,000	8.343	(19)
			\$ (5,678)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Liability ⁽²⁾ (in thousands)
2007	5,220,000	\$ (0.907)	\$ (322)
2008	4,056,000	(1.028)	(211)
2009	2,880,000	(0.592)	(150)
			\$ (683)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability ⁽²⁾ (in thousands)
2007	57,800	\$56.192	\$ (717)
2008	65,400	59.424	(689)
2009	33,000	62.700	(207)
			\$ (1,613)

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability) ⁽²⁾ (in thousands)	Option Type
2007				Puts
	9,900	60.000	13	purchased
2007	9,900	73.380	(27)	Calls sold
2008				Puts
	43,800	60.000	(25)	purchased
2008	43,800	79.544	(166)	Calls sold
2009				Puts
	30,000	60.000	122	purchased
2009	30,000	71.250	(196)	Calls sold
			\$ (279)	

Total net liability	\$	(28,024)
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- (1) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas, light crude and propane prices.
- (2) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.
- (3) Mmbtu represents million British Thermal Units.
- (4) Includes the Partnership's premium received from its sale of an option for it to sell 3,600,000 mmbtu of natural gas at an average price of \$14.33 per mmbtu for the year ended December 31, 2007.
- (5) Includes the Partnership's premium

received from
its sale of an
option for it to
sell 936,000
mmbtu of
natural gas for
the year ended
December 31,
2008 at \$15.50
per mmbtu.

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Total debt consists of the following (in thousands):

	March 31, 2007	December 31, 2006
Revolving credit facility	\$ 53,000	\$ 38,000
Senior notes	285,950	285,977
Other debt	76	106
	339,026	324,083
Less current maturities	(50)	(71)
	\$ 338,976	\$ 324,012

Credit Facility

The Partnership has a \$225.0 million credit facility with a syndicate of banks which matures in June 2011. The credit facility bears interest, at the Partnership's option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding credit facility borrowings at March 31, 2007 was 7.4%. Up to \$50.0 million of the credit facility may be utilized for letters of credit, of which \$7.1 million was outstanding at March 31, 2007. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheet. 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 wholly-owned subsidiaries, and by the guaranty of each of its wholly-owned subsidiaries. The credit facility contains customary covenants, including restrictions on the Partnership's ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is in compliance with these covenants as of March 31, 2007.

The events which constitute an event of default for the Partnership's credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership's General Partner. The credit facility requires the Partnership to maintain a ratio of senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.25 to 1.0; and an interest coverage ratio (as defined in the credit facility) of not less than 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of March 31, 2007, the Partnership's ratio of senior secured debt to EBITDA was 0.8 to 1.0, its funded debt ratio was 4.4 to 1.0 and its interest coverage ratio was 3.5 to 1.0.

The Partnership is unable to borrow under its credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement.

Senior Notes

In December 2005, the Partnership and its subsidiary, Atlas Pipeline Finance Corp. (APFC), issued \$250.0 million of 10-year, 8.125% senior unsecured notes (Senior Notes) in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of \$243.1 million, after underwriting commissions and other transaction costs. In May 2006, the Partnership and APFC issued an additional \$35.0 million of senior unsecured notes at 103% par value, with a resulting effective yield of approximately 7.6%, for net proceeds of approximately \$36.6 million, including accrued interest and net of

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initial purchaser's discount and other transaction costs. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time on or after December 15, 2010 at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Senior Notes are also redeemable at any time prior to December 15, 2010 at stated redemption prices, together with accrued and unpaid interest to the date of redemption. In addition, prior to December 15, 2008, the Partnership may redeem up to 35% of the aggregate principal amount of the Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes 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 the Credit Facility. At March 31, 2007, all of the Partnership's outstanding Senior Notes have been registered with the Securities and Exchange Commission.

The indenture governing the Senior Notes contains covenants, including limitations of the Partnership's ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. The Partnership is in compliance with these covenants as of March 31, 2007.

NOTE 11 COMMITMENTS AND CONTINGENCIES

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on its financial condition or results of operations.

As of March 31, 2007, the Partnership is committed to expend approximately \$50.5 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

NOTE 12 STOCK COMPENSATION*Long-Term Incentive Plan*

The Partnership has a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner's affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by General Partner's managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units. Only phantom units have been granted under the LTIP through March 31, 2007.

A phantom unit entitles a grantee to receive a common unit upon vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. In addition, the Committee may grant a participant a distribution equivalent right (DER), which is the right to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. A unit option entitles the grantee to purchase the Partnership's common limited partner units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through March 31, 2007, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined

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in the LTIP. Of the units outstanding under the LTIP at March 31, 2007, 74,528 units will vest within the following twelve months. All units outstanding under the LTIP at March 31, 2007 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs during both the three months ended March 31, 2007 and 2006 were \$0.1 million. These amounts were recorded as reductions of Partners' Capital on the consolidated balance sheet.

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

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

	Three Months Ended	
	March 31,	
	2007	2006
Outstanding, beginning of period	159,067	110,128
Granted ⁽¹⁾	24,792	728
Matured		
Forfeited		
Outstanding, end of period	183,859	110,856
Non-cash compensation expense recognized (in thousands)	\$ 901	\$ 523

(1) The weighted average price for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense and does not represent an exercise price to be paid by the recipient, was \$50.10 per unit and \$41.11 per unit for awards granted for the three months ended March 31, 2007 and 2006, respectively.

At March 31, 2007, the Partnership had approximately \$4.6 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIP based upon the fair value of the awards.

Incentive Compensation Agreements

The Partnership has incentive compensation agreements which have granted awards to certain key employees retained from previously consummated acquisitions. These individuals are entitled to receive common units of the Partnership upon the vesting of the awards, which is dependent upon the achievement of certain predetermined performance targets. These performance targets include the accomplishment of specific financial goals for the Partnership's Velma system through September 30, 2007 and the financial performance of other previous and future consummated acquisitions, including Elk City and NOARK, through December 31, 2008. The awards associated with the performance targets of the Velma system will vest on September 30, 2007, and awards associated with performance targets of other acquisitions will vest on December 31, 2008.

For the three months ended March 31, 2007 and 2006, the Partnership recognized compensation expense of \$0.9 million and \$0.8 million, respectively, related to the vesting of awards under these incentive compensation agreements. Based upon management's estimate of the probable outcome of the performance targets at March 31, 2007, 223,039 common unit awards are ultimately expected to be issued under these agreements. At March 31, 2007, the Partnership had approximately \$2.1 million of unrecognized compensation expense related to the unvested portion of these awards based upon management's estimate of performance target achievement. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method.

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NOTE 13 RELATED PARTY TRANSACTIONS

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

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates \$0.6 million and \$0.7 million for the three months ended March 31, 2007 and 2006, respectively, for compensation and benefits related to their executive officers. For the three months ended March 31, 2007 and 2006, direct reimbursements were \$6.0 million and \$6.5 million, respectively, including certain costs that have been capitalized by the Partnership. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

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

NOTE 14 OPERATING SEGMENT INFORMATION

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

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

	Three Months Ended March 31,	
	2007	2006
Mid-Continent		
Revenue:		
Natural gas and liquids	\$ 102,176	\$ 100,477
Transportation and compression	9,819	8,750
Other income (loss)	(2,279)	541
Total revenue and other income (loss)	109,716	109,768
Costs and expenses:		
Natural gas and liquids	87,810	85,892
Plant operating	4,530	3,227
Transportation and compression	1,720	1,108
General and administrative	3,894	3,168
Minority interest in NOARK		569
Depreciation and amortization	5,460	4,459
Total costs and expenses	103,414	98,423
Segment profit	\$ 6,302	\$ 11,345
Appalachia		
Revenue:		
Transportation and compression affiliates	\$ 7,720	\$ 7,874
Transportation and compression third parties	19	27
Other income	82	141
Total revenue and other income	7,821	8,042
Costs and expenses:		
Transportation and compression	1,392	968
General and administrative	1,220	884
Depreciation and amortization	1,074	816
Total costs and expenses	3,686	2,668
Segment profit	\$ 4,135	\$ 5,374
Reconciliation of segment profit to net income		
Segment profit:		
Mid-Continent	\$ 6,302	\$ 11,345

Appalachia	4,135	5,374
Total segment profit	10,437	16,719
Corporate general and administrative expenses	(1,219)	(883)
Interest expense	(6,759)	(6,337)
Net income	\$ 2,459	\$ 9,499
Capital Expenditures:		
Mid-Continent	\$ 15,589	\$ 9,420
Appalachia	2,788	4,142
	\$ 18,377	\$ 13,562

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	March 31, 2007	December 31, 2006
Balance sheet		
Total assets:		
Mid-Continent	\$ 727,553	\$ 730,791
Appalachia	43,579	42,448
Corporate other	13,431	13,645
	\$ 784,563	\$ 786,884
Goodwill:		
Mid-Continent	\$ 61,136	\$ 61,136
Appalachia	2,305	2,305
	\$ 63,441	\$ 63,441

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

	Three Months Ended March 31, 2007		2006
Natural gas and liquids:			
Natural gas	\$ 46,763	\$ 56,800	
NGLs	46,773	37,926	
Condensate	2,588	1,518	
Other ⁽¹⁾	6,052	4,233	
Total	\$ 102,176	\$ 100,477	
Transportation and compression:			
Affiliates	\$ 7,720	\$ 7,874	
Third parties	9,838	8,777	
Total	\$ 17,558	\$ 16,651	

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

NOTE 15 SUBSEQUENT EVENT

On April 18, 2007, the Partnership amended the terms of its \$40 million of preferred limited partner unit financing arrangement with Sunlight Capital Partners. Under the amended provisions of the financing arrangement, the preferred units will not be entitled to receive their stated 6.5% per annum dividend until March 13, 2008. The conversion of the preferred units, at Sunlight's option, will be postponed until the date immediately following the first common unit distribution record date after March 13, 2008. In addition, the conversion price for the preferred units was increased to the lesser of \$43.00 or 95% of the market price of the Partnership's common units as of the date of notice of conversion. In connection with this amended arrangement, the Partnership provided Sunlight a premium on its preferred units through the issuance of approximately \$8.5 million of its 8.125% senior unsecured notes at 103% of their par value.

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

Forward-Looking Statements

When used in this Form 10-Q, the words **believes**, **anticipates**, **expects** and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 1A, **Risk Factors**, in our annual report on Form 10-K for 2006. 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.

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 appearing elsewhere in this report.

General

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

Through our Mid-Continent operations, we own and operate:

a FERC-regulated, 565-mile interstate pipeline system that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and which has throughput capacity of approximately 322 MMcfd;

three natural gas processing plants with aggregate capacity of approximately 350 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, all located in Oklahoma; and

1,900 miles of active natural gas gathering systems located in Oklahoma, Arkansas, northern Texas and the Texas panhandle, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing plants or transmission lines.

Through our Appalachian operations, we own and operate 1,600 miles of natural gas gathering systems located in eastern Ohio, western New York and western Pennsylvania. Through an omnibus agreement and other agreements between us and Atlas America, Inc., (Atlas America NASDAQ: ATLS) and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin and a publicly-traded company (NYSE: ATN), we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. Among other things, the omnibus agreement requires Atlas Energy to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America and Atlas Energy under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport.

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Significant Acquisitions

From the date of our initial public offering in January 2000 through March 2007, we have completed six acquisitions at an aggregate cost of approximately \$590.1 million, including, most recently:

In May 2006, we acquired the remaining 25% ownership interest in NOARK from Southwestern Energy Company (Southwestern) for a net purchase price of \$65.5 million, consisting of \$69.0 million in cash to the seller, (including the repayment of the \$39.0 million of outstanding NOARK notes at the date of acquisition), less the seller's interest in working capital at the date of acquisition of \$3.5 million. In October 2005, we acquired from Enogex, a wholly-owned subsidiary of OGE Energy Corp., all of the outstanding equity of Atlas Arkansas, which owned the initial 75% ownership interest in NOARK, for \$163.0 million, plus \$16.8 million for working capital adjustments and related transaction costs. NOARK's principal assets include the Ozark Gas Transmission system, a 565-mile interstate natural gas pipeline, and Ozark Gas Gathering, a 365-mile natural gas gathering system.

Contractual Revenue Arrangements

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

the volumes of natural gas we gather, transport and process which, in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas they produce, and the demand for natural gas and NGLs; and

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

In our Appalachian region, substantially all of the natural gas we transport is for Atlas Energy under percentage-of-proceeds (POP) contracts, as described below, in which we earn a fee equal to a percentage, generally 16%, of the selling price of the natural gas subject, in most cases, to a minimum of \$0.35 or \$0.40 per thousand cubic feet, or mcf, depending upon the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has always exceeded this minimum in general. The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our revenue in the Mid-Continent region is determined primarily by the fees earned from our transmission, gathering and processing operations. We either purchase natural gas from producers and move it into receipt points on our pipeline systems, and then sell the natural gas, or produced NGLs, if any, off of delivery points on our systems, or we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation services are provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

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

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

Keep-Whole Contracts. These contracts require us, as the processor, to bear the economic risk (the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that we paid for the unprocessed natural gas. However, because the natural gas received by the Elk City/Sweetwater system, which is currently our only gathering system with keep-whole contracts, is generally low in liquids content and meets downstream pipeline specifications without being processed, the natural gas can be bypassed around the Elk City and Sweetwater processing plants and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with such type of contracts is minimized.

Recent Trends and Uncertainties

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

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

As a result of our POP and keep-whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas and NGLs. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. The number of active oil and gas rigs has increased in recent years, mainly due to recent significant increases in natural gas prices, which could result in sustained increases in drilling activity during the current and future periods. However, energy market uncertainty could negatively impact North American drilling activity in the short term. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. A 10% change in the average price of NGLs, natural gas and condensate we process and

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sell would result in a change to our consolidated income for the twelve-month period ending March 31, 2008 of approximately \$7.7 million.

Results of Operations

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

	Three Months Ended March 31,	
	2007	2006
Operating data:		
Appalachia:		
Average throughput volumes mcf	62,532	57,326
Average transportation rate per mcf	\$ 1.38	\$ 1.53
Mid-Continent:		
Velma system:		
Gathered gas volume mcf	61,017	60,715
Processed gas volume mcf	58,508	58,528
Residue gas volume mcf	45,689	45,754
NGL volume bpd	6,247	6,334
Condensate volume bpd	200	186
Elk City/Sweetwater system:		
Gathered gas volume mcf	287,892	252,190
Processed gas volume mcf	207,253	130,955
Residue gas volume mcf	190,940	119,016
NGL volume bpd	8,515	5,758
Condensate volume bpd	322	171
NOARK system:		
Average Ozark Gas Transmission throughput volume mcf	286,891	239,151

Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006

Revenue. Natural gas and liquids revenue was \$102.2 million for the three months ended March 31, 2007, an increase of \$1.7 million from \$100.5 million for the three months ended March 31, 2006. The increase was primarily attributable to an increase of \$16.4 million from the Elk City system due primarily to an increase in volumes, which includes processing volumes from the newly constructed Sweetwater gas plant. This increase is partially offset by a decrease of \$11.8 million from the NOARK system due primarily to lower natural gas sales volumes on its gathering systems and a decrease of \$2.9 million from the Velma system due to lower commodity prices compared with the prior year period. Gross natural gas gathered on the Elk City system averaged 287.9 MMcfd for the three months ended March 31, 2007, an increase of 14.2% from the comparable prior year period. Gross natural gas gathered averaged 61.0 MMcfd on the Velma system for the three months ended March 31, 2007, an increase of 0.5% from the comparable prior year period. 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*.

Transportation and compression revenue increased to \$17.6 million for the three months ended March 31, 2007 compared with \$16.7 million for the prior year period. This \$0.9 million increase was primarily due to an increase of \$0.8 million from the transportation revenues associated with the NOARK system. For the NOARK system, average Ozark Gas Transmission volume was 286.9 MMcfd for the three months ended March 31, 2007, an increase of 20% from the prior year comparable period. The Appalachia system's average

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throughput volume was 62.5 MMcfd for the three months ended March 31, 2007 as compared with 57.3 MMcfd for the three months ended March 31, 2006, an increase of 5.2 MMcfd or 9.1%. The Appalachia system's average transportation rate was \$1.38 per Mcf for the three months ended March 31, 2007 compared with \$1.53 per Mcf for the prior year period, a decrease of \$0.15 per Mcf as a result of lower natural gas prices. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system.

Other income (loss), including the impact of gains and losses recognized on derivatives, was a loss of \$2.2 million for the three months ended March 31, 2007, a decrease of \$2.9 million from the prior year. This decrease was due primarily to a \$2.8 million unfavorable movement in derivative gains and losses compared with the prior year as a result of unfavorable movements in commodity prices.

Costs and Expenses. Natural gas and liquids cost of goods sold of \$87.8 million and plant operating expenses of \$4.5 million for the three months ended March 31, 2007 represented increases of \$1.9 million and \$1.3 million, respectively, from the comparable prior year amounts due primarily to an increase in gathered and processed natural gas volumes on the Elk City System, which includes contributions from the Sweetwater processing facility, partially offset by a decrease in NOARK gathering system natural gas purchases and a decrease in commodity prices on the Velma system. Transportation and compression expenses increased \$1.0 million to \$3.1 million for the three months ended March 31, 2007 due to higher NOARK and Appalachia system operating and maintenance costs as a result of increased capacity and additional well connections.

General and administrative expenses, including amounts reimbursed to affiliates, increased \$1.4 million to \$6.3 million for the three months ended March 31, 2007 compared with \$4.9 million for the prior year comparable period. This increase was mainly due to a \$0.5 million increase in non-cash compensation expense related to vesting of phantom and common unit awards and higher costs associated with managing our business, including management time related to acquisition and capital raising opportunities.

Depreciation and amortization increased to \$6.5 million for the three months ended March 31, 2007 compared with \$5.3 million for the three months ended March 31, 2006 due primarily to the depreciation associated with the portion of the NOARK assets acquired during 2006 and our 2006 expansion capital expenditures, particularly the Sweetwater processing facility.

Interest expense increased to \$6.8 million for the three months ended March 31, 2007 as compared with \$6.3 million for the comparable prior year period. This \$0.5 million increase was primarily due to interest associated with our May 2006 issuance of \$35.0 million principal amount of 10-year senior unsecured notes and additional borrowings under our credit facility, partially offset by the absence in the current period of interest associated with \$39.0 million of the outstanding NOARK notes, which were assumed by the seller as part of our acquisition of the remaining 25% ownership interest in NOARK in May 2006.

Minority interest in NOARK of \$0.6 million for the prior year comparable period represents Southwestern's 25% ownership interest in the net income of NOARK during the prior year period. We acquired the remaining 25% ownership interest in May 2006.

During June 2006, we identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and first quarter of 2006, we recorded an adjustment of \$1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the \$1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively. Our management believes that the impact of these adjustments is immaterial to its current and prior financial statements.

Table of Contents**Liquidity and Capital Resources**

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 unitholders and general partner. In general, we expect to fund:

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

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

debt principal payments through additional borrowings as they become due or by the issuance of additional limited partner units.

At March 31, 2007, we had \$53.0 million of outstanding borrowings under our credit facility and \$7.1 million of outstanding letters of credit which are not reflected as borrowings on our consolidated balance sheet, and \$164.9 million of remaining committed capacity under the \$225.0 million credit facility, subject to covenant limitations (see [Credit Facility](#)). In addition to the availability under the credit facility, we have a universal shelf registration statement on file with the Securities and Exchange Commission, which allows us to issue equity or debt securities (see [Shelf Registration Statement](#)) of which \$352.1 million remains available at March 31, 2007. At March 31, 2007, we had a working capital deficit of \$10.3 million compared with a working capital surplus of \$1.2 million at December 31, 2006. This decrease was primarily due to an increase in the current portion of our net hedge liability between periods, which is the result of changes in commodity prices after we entered into the hedges. The majority of our hedge transactions qualify as effective cash flow hedges, and changes in commodity prices with respect to these hedge transactions are reflected as adjustments to accumulated other comprehensive loss within partners' capital on the consolidated balance sheet. We believe that we have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, quarterly cash distributions, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings and the issuance of additional limited partner units.

Cash Flows Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006

Net cash provided by operating activities of \$19.0 million for the three months ended March 31, 2007 represented an increase of \$8.9 million from \$10.1 million for the comparable prior year period. The increase was derived principally from a \$12.1 million increase in cash resulting from working capital changes, a \$2.8 million increase from non-cash movements on derivatives and a \$1.3 million increase in depreciation and amortization. These amounts were partially offset by a \$7.0 million decrease in net income.

Net cash used in investing activities was \$18.3 million for the three months ended March 31, 2007, an increase of \$4.7 million from \$13.6 million for the comparable prior year period. This increase was principally due to a \$4.8 million increase in capital expenditures. See further discussion of capital expenditures under [Capital Requirements](#) .

Net cash used in financing activities was \$0.7 million for the three months ended March 31, 2007, a decrease of \$7.7 million from \$7.0 million of net cash provided by financing activities for the comparable prior year period. This decrease was principally due to the \$30.0 million of net proceeds from the issuance of our cumulative convertible preferred units in March 2006 and an increase of \$1.4 million in cash distributions to common limited partners and the general partner due mainly to increases in our common limited partner units outstanding and our cash distribution amount per common limited partner unit, partially offset by a \$24.5 million increase in net borrowings under our credit facility.

Table of Contents**Capital Requirements**

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

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

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

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

	Three Months Ended March 31,	
	2007	2006
Maintenance capital expenditures	\$ 772	\$ 1,161
Expansion capital expenditures	17,605	12,401
Total	\$ 18,377	\$ 13,562

Expansion capital expenditures increased to \$17.6 million for the three months ended March 31, 2007, due principally to expansions of the Appalachia, Velma and Elk City gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. Maintenance capital expenditures for the three months ended March 31, 2007 decreased to \$0.8 million compared with the prior year comparable period due to fluctuations in the timing of scheduled maintenance activity. As of March 31, 2007, we are committed to expend approximately \$50.5 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Partnership Distributions

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

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

Available cash is initially distributed 98% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The general partner's incentive distributions declared during the

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three months ended March 31, 2007 were \$3.9 million.

Common Equity Offering

In May 2006, we sold 500,000 common units to Wachovia Securities, which then offered the common units to public investors. The units, which were issued under our previously filed shelf registration statement, resulted in net proceeds of approximately \$19.7 million, after underwriting commissions and other transaction costs. We utilized the net proceeds from the sale to partially repay borrowings under our credit facility made in connection with our acquisition of the remaining 25% ownership interest in NOARK.

Shelf Registration Statement

We have an effective shelf registration statement with the Securities and Exchange Commission that permits us to periodically issue equity and debt securities for a total value of up to \$500 million. As of March 31, 2007, \$352.1 million remains available for issuance under the shelf registration statement. However, the amount, type and timing of any offerings will depend upon, among other things, our funding requirements, prevailing market conditions, and compliance with our credit facility covenants.

Private Placement of Convertible Preferred Units

On March 13, 2006, we entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC, an affiliate of Elliott & Associates, for aggregate gross proceeds of \$30.0 million. We also sold an additional 10,000 6.5% cumulative preferred units to Sunlight Capital Partners for \$10.0 million on May 19, 2006, pursuant to our right to require Sunlight Capital Partners to purchase such additional units under the agreement with Sunlight. The preferred units are entitled to receive dividends of 6.5% per annum commencing on March 13, 2007, which will accrue and be paid quarterly on the same date as the distribution payment date for our common units. The preferred units are convertible, at the holder's option, into common units commencing on the date immediately following the first record date after March 13, 2007 at a conversion price equal to the lesser of \$41.00 or 95% of the market price of our common units as of the date of the notice of conversion. We may elect to pay cash rather than issue common units in satisfaction of a conversion request. We have the right to call the preferred units at a specified premium. We have filed a registration statement to cover the resale of the common units underlying the preferred units. The net proceeds from the initial issuance of the preferred units were used to fund a portion of our capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under our credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK. The preferred units are reflected on our consolidated balance sheet as preferred equity within Partners' Capital. If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within Partners' Capital on our consolidated balance sheet. Dividends accrued and paid on the preferred units and the premium paid upon their redemption, if any, will be recognized as a reduction to our net income in determining net income attributable to common unitholders and the general partner.

On April 18, 2007, we amended the terms of our \$40 million of preferred limited partner unit financing arrangement with Sunlight Capital Partners. Under the amended provisions of the financing arrangement, the preferred units will not be entitled to receive their stated 6.5% per annum dividend until March 13, 2008. The conversion of the preferred units, at Sunlight's option, will be postponed until the date immediately following the first common unit distribution record date after March 13, 2008. In addition, the conversion price for the preferred units was increased to the lesser of \$43.00 or 95% of the market price of our common units as of the date of notice of conversion. In connection with this amended arrangement, we provided Sunlight a premium on our preferred units through the issuance of approximately \$8.5 million of our 8.125% senior unsecured notes at 103% of their par value.

Table of Contents**Credit Facility**

We have a \$225.0 million credit facility with a syndicate of banks which matures in June 2011. The credit facility bears interest, at our option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding credit facility borrowings at March 31, 2007 was 7.4%. Up to \$50.0 million of the credit facility may be utilized for letters of credit, of which \$7.1 million was outstanding at March 31, 2007. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet. Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our wholly-owned subsidiaries, and by the guaranty of each of our wholly-owned subsidiaries. The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are in compliance with these covenants as of March 31, 2007.

The events which constitute an event of default are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against us in excess of a specified amount, and a change of control of our general partner. The credit facility requires us to maintain a ratio of senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.25 to 1.0; and an interest coverage ratio (as defined in the credit facility) of not less than 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of March 31, 2007, our ratio of senior secured debt to EBITDA was 0.8 to 1.0, our funded debt ratio was 4.4 to 1.0 and our interest coverage ratio was 3.5 to 1.0.

We are unable to borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement.

Senior Notes

In December 2005, we and our subsidiary, Atlas Pipeline Finance Corp. (APFC), issued \$250.0 million of 10-year, 8.125% senior unsecured notes (Senior Notes) in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of \$243.1 million, after underwriting commissions and other transaction costs. In May 2006, we and APFC issued an additional \$35.0 million of senior unsecured notes at 103% par value, with a resulting effective yield of approximately 7.6%, for net proceeds of approximately \$36.6 million, including accrued interest and net of initial purchaser's discount and other transaction costs. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time on or after December 15, 2010 at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Senior Notes are also redeemable at any time prior to December 15, 2010 at stated redemption prices, together with accrued and unpaid interest to the date of redemption. In addition, prior to December 15, 2008, we may redeem up to 35% of the aggregate principal amount of the Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes 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 the credit facility. At March 31, 2007, all of our outstanding Senior Notes have been registered with the Securities and Exchange Commission.

The indenture governing the Senior Notes contains covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay

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distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We are in compliance with these covenants as of March 31, 2007.

NOARK Notes

On May 2, 2006, we acquired the remaining 25% equity ownership interest in NOARK from Southwestern. Prior to this acquisition, NOARK's subsidiary, NOARK Pipeline Finance, L.L.C., had \$39.0 million in principal amount outstanding of 7.15% notes due in 2018, which was presented as debt on our consolidated balance sheet, to be allocated severally 100% to Southwestern. In connection with the acquisition of the 25% equity ownership interest in NOARK, Southwestern acquired NOARK Pipeline Finance, L.L.C. and agreed to retain the obligation for the outstanding NOARK notes, with the result that neither we nor NOARK have any further liability with respect to such notes.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make 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 revenues and expenses during the reporting period. Although we believe our estimates are reasonable, actual results could differ from those estimates. 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, 2006, and there have been no material changes to these policies through March 31, 2007.

New Accounting Standards

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159). SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The Statement will be effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. The Statement offers various options in electing to apply the provisions of this Statement, and at this time we have not made any decisions with regards to its application to our financial position or results of operations. We are currently evaluating whether SFAS No. 159 will have an impact on our financial position and results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value statements. This statement does not require any new fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating whether SFAS No. 157 will have an impact on our financial position and results of operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in interest rates and oil and gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-

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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 financial instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on March 31, 2007. Only the potential impact of hypothetical assumptions are analyzed. The analysis does not consider other possible effects that could impact our business.

Interest Rate Risk. At March 31, 2007, we had a \$225.0 million revolving credit facility (\$53.0 million outstanding) to fund the expansion of our existing gathering systems, acquire other natural gas gathering systems and fund working capital movements as needed. The weighted average interest rate for these borrowings was 7.4% at March 31, 2007. Holding all other variables constant, a 1% change in interest rates would change interest expense by \$0.5 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of commodities 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. Based on our current portfolio of natural gas supply contracts, we have long condensate, NGL, and natural gas positions. A 10% change in the average price of NGLs, natural gas and condensate we process and sell would result in a change to our consolidated income for the twelve-month period ending March 31, 2008 of approximately \$7.7 million.

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. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these 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. Option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133).

We formally document all relationships between hedging instruments and the items being hedged, including our risk management objective and strategy for undertaking the hedging transactions. This includes matching the natural gas futures and options contracts to the forecasted transactions. We assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in offsetting changes in the forecasted cash flow of hedged items. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of correlation between the hedging instrument and the underlying commodity, we will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which we determine through utilization of market data, will be recognized immediately within other income in our consolidated statements of income.

Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners' capital.

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as accumulated other comprehensive income (loss), and reclassify them to natural gas and liquids revenue within our consolidated statements of income as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within other income in our consolidated statements of income as they occur. At March 31, 2007 and December 31, 2006, we reflected net derivative liabilities on our consolidated balance sheets of \$28.0 million and \$20.1 million, respectively. Of the \$27.7 million of net loss in accumulated other comprehensive loss within partners' capital on our consolidated balance sheet at March 31, 2007, if the fair values of the instruments remain at current market values, we will reclassify \$17.0 million of losses to natural gas and liquids revenue in our consolidated statements of income over the next twelve month period as these contracts expire, and \$10.7 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes. Ineffective hedge gains or losses are recorded within other income in our consolidated statements of income while the hedge contracts are open and may increase or decrease until settlement of the contract. We recognized losses of \$3.0 million and \$2.4 million for the three months ended March 31, 2007 and 2006, respectively, within natural gas and liquids revenue in our consolidated statements of income related to the settlement of qualifying hedge instruments. We recognized losses of \$1.3 million and \$1.0 million within other income in our consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the three months ended March 31, 2007. We recognized a gain of \$0.5 million for the three months ended March 31, 2006 within other income in our consolidated statements of income related to the change in market value of the ineffective portion of qualifying derivatives only. For the three months ended March 31, 2006, we did not have any non-qualifying derivatives.

A portion of our future natural gas, NGL and condensate sales is periodically hedged through the use of swaps and collar contracts. Realized gains and losses on the derivative instruments that are classified as effective hedges are reflected in the contract month being hedged as an adjustment to natural gas and liquids revenue within our consolidated statements of income.

As of March 31, 2007, we had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability ⁽¹⁾ (in thousands)
2007	71,631,000	\$0.901	\$ (9,221)
2008	33,012,000	0.697	(9,076)
2009	8,568,000	0.746	(2,113)
			\$ (20,410)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability) ⁽²⁾ (in thousands)	Option Type
2008	693,600	38,744,000	\$60.00	\$ 2,526	Puts purchased
2008	693,600	38,744,000	84.00	(2,570)	Calls sold
2009	720,000	40,219,000	60.00	3,314	Puts purchased
2009	720,000	40,219,000	81.00	(1,838)	Calls sold

Table of Contents**Natural Gas Sales**

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Liability ⁽²⁾ (in thousands)
2007	810,000	\$ 7.255	\$ (798)
2008	240,000	7.270	(395)
2009	480,000	8.000	(162)
			\$ (1,355)

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Asset ⁽²⁾ (in thousands)
2007	810,000	\$ (0.535)	\$ 362
2008	240,000	(0.555)	150
2009	480,000	(0.540)	50
			\$ 562

Natural Gas Purchases

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Liability ⁽²⁾ (in thousands)
2007	5,220,000	\$ 8.854 ⁽⁴⁾	\$ (4,926)
2008	4,056,000	8.719 ⁽⁵⁾	(733)
2009	2,880,000	8.343	(19)
			\$ (5,678)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu) ⁽³⁾	Average Fixed Price (per mmbtu) ⁽³⁾	Fair Value Liability ⁽²⁾ (in thousands)
2007	5,220,000	\$ (0.907)	\$ (322)
2008	4,056,000	(1.028)	(211)
2009	2,880,000	(0.592)	(150)
			\$ (683)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability ⁽²⁾ (in thousands)
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2007	57,800	\$56.192	\$	(717)
2008	65,400	59.424		(689)
2009	33,000	62.700		(207)
			\$	(1,613)

Table of Contents**Crude Oil Sales Options**

Production Period Ended December 31, 2007	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability) ⁽²⁾ (in thousands)	Option Type
	9,900	60.000	13	Puts purchased
2007	9,900	73.380	(27)	Calls sold
2008				Puts
	43,800	60.000	(25)	purchased
2008	43,800	79.544	(166)	Calls sold
2009				Puts
	30,000	60.000	122	purchased
2009	30,000	71.250	(196)	Calls sold
			\$ (279)	
	Total net liability		\$ (28,024)	

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

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

(3) Mmbtu represents million British Thermal Units.

(4)

Includes our premium received from our sale of an option for us to sell 3,600,000 mmbtu of natural gas at an average price of \$14.33 per mmbtu for the year ended December 31, 2007.

- (5) Includes our premium received from our sale of an option for us to sell 936,000 mmbtu of natural gas for the year ended December 31, 2008 at \$15.50 per mmbtu.

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 our disclosure controls and procedures are effective at the reasonable assurance level.

As of December 31, 2006, management concluded that our internal control over financial reporting was ineffective, based on our evaluation under the COSO framework, because it identified a material weakness with regard to our accounting for certain derivative instruments in accordance with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Specifically, we entered into a significant number of option instruments (a combination of puts purchased and calls sold that are commonly known as costless collars) in September 2006 to hedge our exposure to movements in commodity prices that were not appropriately valued within our consolidated financial statements under the provisions of SFAS No. 133. While the costless collars were valued appropriately with regard to their intrinsic value, we did not record a fair value for the time-value component of

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the derivative instruments. All of our other derivative instruments that were in effect during 2006 had been appropriately recorded within our consolidated financial statements as of December 31, 2006. This material weakness resulted in the amendment of our Form 10-Q as of September 30, 2006.

Subsequent to our discovery of the material weakness discussed above, in early 2007 we took steps to remediate the material weakness, including reviewing the accounting requirements necessary for compliance with SFAS No. 133 and establishing additional review procedures of accounting for derivative transactions by senior personnel within our organization. We believe these actions have strengthened our internal control over financial reporting and address the material weakness identified.

PART II. OTHER INFORMATION**ITEM 6. EXHIBITS**

Exhibit No.	Description
3.1	Second Amended and Restated Agreement of Limited Partnership ⁽¹⁾
3.2	Certificate of Limited Partnership of Atlas Pipeline Partners, L.P. ⁽²⁾
3.3a	Certificate of Designation of 6.5% Cumulative Convertible Preferred Units ⁽³⁾
3.3b	Amended and Restated Certificate of Designation of 6.5% Cumulative Convertible Preferred Units ⁽⁴⁾
10.1	Securities Purchase Agreement dated as of March 13, 2006 between the Partnership and Sunlight Capital Partners, LLC ⁽³⁾
10.2	Registration Rights Agreement dated as of March 13, 2006 between the Partnership and Sunlight Capital Partners, LLC ⁽³⁾
10.3	Securities Purchase Agreement dated as of April 18, 2007 among the Partnership, Atlas Pipeline Finance Corp. and Sunlight Capital Partners, LLC ⁽⁴⁾
10.4	Registration Rights Agreement dated as of April 18, 2007 among the Partnership, Atlas Pipeline Finance Corp. and Sunlight Capital Partners, LLC ⁽⁴⁾
31.1	Rule 13a-14(a)/15d-14(a) Certifications
31.2	Rule 13a-14(a)/15d-14(a) Certifications
32.1	Section 1350 Certifications
32.2	Section 1350 Certifications

⁽¹⁾ Previously filed as an exhibit to the Partnership's registration statement on Form S-3, Registration No. 333-113523 and incorporated

herein by
reference.

(2) Previously filed
as an exhibit to
the Partnership's
registration
statement on
Form S-1,
Registration
No. 333-85193
and incorporated
herein by
reference.

(3) Previously filed
as an exhibit to
the Partnership's
current report on
Form 8-K, filed
on March 14,
2006 and
incorporated
herein by
reference.

(4) Previously filed
as an exhibit to
the Partnership's
current report on
Form 8-K, filed
on April 19,
2007 and
incorporated
herein by
reference.

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SIGNATURES

ATLAS PIPELINE PARTNERS, L.P.

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.

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

Date: May 4, 2007

By: /s/ EDWARD E. COHEN
Edward E. Cohen
Chairman of the Managing Board of the
General Partner Chief Executive Officer of
the General Partner

Date: May 4, 2007

By: /s/ MICHAEL L. STAINES
Michael L. Staines
President, Chief Operating Officer and
Managing Board Member of the General
Partner

Date: May 4, 2007

By: /s/ MATTHEW A. JONES
Matthew A. Jones
Chief Financial Officer of the General
Partner

Date: May 4, 2007

By: /s/ SEAN P. MCGRATH
Sean P. McGrath
Chief Accounting Officer of the General
Partner