ATLAS PIPELINE PARTNERS LP
Form 10-Q
May 05, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2006

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______ to______

Commission file number: 1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
311 Rouser Road	
Moon Township, Pennsylvania	**15108**

(Address of principal executive office) **(Zip code)**

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

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

Indicate by check mark whether the registrant 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 x 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 x

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO QUARTERLY REPORT

ON FORM 10-Q

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	March 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 37,789	$ 34,237
Accounts receivable affiliates	4,107	4,649
Accounts receivable	55,132	57,528
Current portion of hedge asset	2,337	11,388
Prepaid expenses and other	5,076	2,454
Total current assets	104,441	110,256
Property, plant and equipment, net	454,482	445,066
Long-term hedge asset	587	4,388
Intangible assets, net	53,707	54,869
Goodwill	110,632	111,446
Other assets, net	16,088	16,701
	$ 739,937	$ 742,726
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 1,284	$ 1,263
Accounts payable	6,602	15,609
Accrued liabilities	27,054	16,064
Current portion of hedge liability	13,053	23,796
Accrued producer liabilities	28,317	36,712
Total current liabilities	76,310	93,444
Long-term hedge liability	18,040	22,410
Long-term debt, less current portion	287,892	297,362
Commitments and contingencies		
Partners capital:		
Preferred limited partner s interest	28,215	
Common limited partners interests	346,136	349,491
General partner s interest	10,645	10,094
Accumulated other comprehensive loss	(27,301)	(30,075)
Total partners capital	357,695	329,510

$ 739,937	$ 742,726

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Revenue:		
Natural gas and liquids	$ 101,017	$ 42,334
Transportation and compression affiliates	7,874	4,847
Transportation and compression third parties	8,777	15
Interest income and other	142	81
Total revenue and other income	117,810	47,277
Costs and expenses:		
Natural gas and liquids	85,892	35,459
Plant operating	3,227	1,204
Transportation and compression	2,322	676
General and administrative	3,969	1,975
Compensation reimbursement affiliates	720	513
Depreciation and amortization	5,275	1,929
Interest	6,337	1,135
Minority interest in NOARK	569	
Other		136
Total costs and expenses	108,311	43,027
Net income	9,499	4,250
Preferred unit imputed dividend cost	(95)	
Net income attributable to common limited partners and the general partner	$ 9,404	$ 4,250
Allocation of net income attributable to common limited partners and the general partner:		
Common limited partners interest	$ 5,806	$ 2,830
General partner s interest	3,598	1,420
Net income attributable to common limited partners and the general partner	$ 9,404	$ 4,250
Net income attributable to common limited partners per unit:		
Basic	$ 0.46	$ 0.39
Diluted	$ 0.46	$ 0.39
Weighted average common limited partner units outstanding:		
Basic	12,549	7,205
Diluted	12,687	7,225

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE THREE MONTHS ENDED MARCH 31, 2006

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units						
	Preferred	Common	Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Total Partners Capital
Balance at January 1, 2006		12,549,266	$	$ 349,491	$ 10,094	$ (30,075)	$ 329,510
Issuance of 6.5% cumulative convertible preferred limited partner units	30,000		28,120				28,120
Preferred unit imputed dividend Cost			95				95
General partner capital contribution					591		591
Unissued common units under incentive plans				1,319			1,319
Distributions paid to common limited partners and the general partner				(10,416)	(3,638)		(14,054)
Distribution equivalent rights paid on unissued units under incentive plans				(92)			(92)
Other comprehensive income						2,774	2,774
Other				28			28
Net income attributable to common limited partners and the general partner				5,806	3,598		9,404
Balance at March 31, 2006	30,000	12,549,266	$ 28,215	$ 346,136	$ 10,645	$ (27,301)	$ 357,695

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Three Months Ended March 31, 2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income attributable to common limited partners and the general partner	$ 9,404	$ 4,250
Adjustments to reconcile net income attributable to common limited partners and the general partner to net cash provided by operating activities:		
Depreciation and amortization	5,275	1,929
Non-cash loss/(gain) on derivative value	513	(75)
Non-cash compensation expense	1,319	449
Amortization of deferred finance costs	593	182
Minority interest in NOARK	569	
Preferred unit imputed dividend cost amortization	95	
Change in operating assets and liabilities, net of effects of acquisition:		
Accounts receivable and prepaid expenses and other	(169)	(2,743)
Accounts payable and accrued liabilities	(8,041)	459
Accounts payable and accounts receivable affiliates	542	2,459
Net cash provided by operating activities	10,100	6,910
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net cash paid for acquisition		(526)
Capital expenditures	(13,562)	(6,077)
Other	(4)	(426)
Net cash used in investing activities	(13,566)	(7,029)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	9,500	
Repayments under credit facility	(19,000)	(579)
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	(14,054)	(6,467)
Other	(13)	(1,354)
Net cash provided by/(used in) financing activities	7,018	(8,400)
Net change in cash and cash equivalents	3,552	(8,519)
Cash and cash equivalents, beginning of period	34,237	18,214
Cash and cash equivalents, end of period	$ 37,789	$ 9,695

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

MARCH 31, 2006

(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded Delaware limited partnership formed in May 1999 to acquire, own and operate natural gas gathering systems previously owned by Atlas America, Inc. and its affiliates (Atlas America), a publicly traded company (NASDAQ: ATLS). 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 (a wholly-owned subsidiary of Atlas America (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 yet 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, 2006, the Partnership had 12,549,266 common limited partnership units, including 1,641,026 unregistered common units held by the General Partner, and 30,000 $1,000 par value cumulative convertible preferred limited partnership units outstanding (see Note 4).

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2005 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, 2005. The results of operations for the three month period ended March 31, 2006 may not necessarily be indicative of the results of operations for the full year ending December 31, 2006.

Certain amounts in the prior years consolidated financial statements have been reclassified to conform to the current year presentation.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership s significant accounting policies is included in its audited consolidated financial statements and notes thereto in its annual report on Form 10-K for the year ended December 31, 2005.

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 owns a 75% operating interest (see Note 8 and Note 15). The remaining 25% interest in NOARK is owned by Southwestern Energy Pipeline Company

(Southwestern), a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Under the NOARK partnership agreement, Southwestern is responsible for the $39.0 million of outstanding long-term debt, including interest thereon, of NOARK at March 31, 2006 (see Note 10). Any repayment of the long-term debt and related interest expense will be made from amounts otherwise distributable to Southwestern and, if that amount is insufficient, Southwestern is required to make a capital contribution to NOARK. The Partnership consolidates 100% of NOARK s financial statements. The minority interest expense reflected on the Partnership s consolidated statements of income represents Southwestern s 25% ownership interest in NOARK s net income before interest expense and interest expense related to NOARK s long-term debt.

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.

The natural gas industry principally conducts it 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, 2006 represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

Net Income Per Unit

Basic net income attributable to common limited partners per unit is computed by dividing net income attributable to common limited partners, which is after the deduction of the general partner s interest, by the weighted average number of common limited partner units outstanding during the period. The General Partner s interest in net income attributable to common limited partners and the General Partner is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 5). 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 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 to those used to compute diluted net income attributable to common limited partners per unit (in thousands):

	Three Months Ended	
	March 31,	
	2006	**2005**
Weighted average number of common limited partner units basic	12,549	7,205
Add: effect of dilutive unit incentive awards	138	20
Weighted average number of common limited partner units diluted	12,687	7,225

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income attributable to common limited partners and the General Partner 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 attributable to common limited partners and the General Partner, are referred to as other comprehensive income (loss) and include only changes in the fair value of unsettled hedging contracts. The following table sets forth the calculation of the Partnership s comprehensive income (loss) (in thousands):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Net income	$ 9,499	$ 4,250
Preferred unit imputed dividend cost	(95)	
Net income attributable to common limited partners and the general partner	9,404	4,250
Other comprehensive income (loss):		
Changes in fair value of derivative instruments accounted for as hedges	374	(8,938)
Add: reclassification adjustment for losses in net income	2,400	669
Total other comprehensive income (loss)	2,774	(8,269)
Comprehensive income (loss)	$ 12,178	$ (4,019)

Revenue Recognition

Revenues in the Appalachia segment are recognized at the time the natural gas is transported through the gathering systems. Under the terms of its natural gas gathering agreements with Atlas America and its affiliates, the Partnership receives fees for gathering natural gas from wells owned by Atlas America and by drilling investment partnerships sponsored by Atlas America. The fees received for the gathering services under the Atlas America agreements are generally the greater of 16% of the gross sales price for gas produced from the wells, or $0.35 or $0.45 per thousand cubic feet (mcf), depending on the ownership of the well. Substantially all gas gathering revenues are derived under 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. The Partnership either purchases gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced natural gas liquids (NGLs), if any, off of delivery points on its systems, or the Partnership transports natural gas across its systems, from receipt to delivery point, without taking title to the 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 are 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, 2006 and December 31, 2005 of $33.1 million and $48.4 million, respectively, 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 8.1% and the amount of interest capitalized was $0.3 million for the three months ended March 31, 2006. There were no amounts capitalized for the three months ended March 31, 2005.

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, 2006 and December 31, 2005 (in thousands):

	March 31, 2006	December 31, 2005	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 23,990	$ 23,990	8
Customer relationships	32,960	32,960	20
	$ 56,950	$ 56,950	
Accumulated Amortization:			
Customer contracts	$ (2,089)	$ (1,339)	
Customer relationships	(1,154)	(742)	
	$ (3,243)	$ (2,081)	
Net Carrying Amount:			
Customer contracts	$ 21,901	$ 22,651	
Customer relationships	31,806	32,218	
	$ 53,707	$ 54,869	

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. Customer contract and customer relationship intangible assets are amortized on a straight-line basis. Amortization expense on intangible assets was $1.2 million for the three months ended March 31, 2006. There was no amortization expense on intangible assets recorded during the three months ended March 31, 2005. Amortization expense related to intangible assets is estimated to be $4.6 million for each of the next five calendar years commencing in 2006.

Goodwill

At March 31, 2006 and December 31, 2005, the Partnership had $110.6 million and $111.4 million, respectively, 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, 2006 and 2005 were as follows (in thousands):

	Three Months Ended March 31, 2006	2005
Balance, beginning of period	$ 111,446	$ 2,305
Reduction in minority interest deficit acquired	(569)	
Adjustment of purchase price allocation NOARK	(245)	
Balance, end of period	$ 110,632	$ 2,305

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, Goodwill and Other Intangible Assets, 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, 2005 resulted in no impairment, and no impairment indicators have been noted as of March 31, 2006. 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.

NOTE 3 COMMON UNIT EQUITY OFFERINGS

In November 2005, the Partnership sold 2,700,000 of its common units in a public offering for gross proceeds of $113.4 million. In addition, pursuant to an option granted to the underwriters of the offering, the Partnership sold an additional 330,000 common units in December 2005 for gross proceeds of $13.9 million, resulting in aggregate total gross proceeds of $127.3 million. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in total net proceeds of approximately $121.0 million, after underwriting commissions and other transaction costs. The Partnership primarily utilized the net proceeds from the sale to repay a portion of the amounts due under its credit facility.

In June 2005, the Partnership sold 2,300,000 common units in a public offering for total gross proceeds of $96.5 million. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in net proceeds of approximately $91.7 million, after underwriting commissions and other transaction costs. The Partnership primarily utilized the net proceeds from the sale to repay a portion of the amounts due under its credit facility.

NOTE 4 PREFERRED UNIT EQUITY OFFERING

On March 13, 2006, the Partnership sold 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC, an affiliate of Elliott & Associates, for aggregate proceeds of $30.0 million. The Partnership has the right, subject to specified conditions, before June 11, 2006, to require Sunlight Capital Partners to purchase an additional 10,000 preferred units on the same terms. 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 the Partnership s common units. 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 agreed to file a registration statement to cover the resale of the common units underlying the preferred units. The net proceeds from the issuance of the preferred units will be 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 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 preferred units not having a dividend yield during the first year after their issuance on March 13, 2006. The initial imputed dividend cost of $1.9 million on the preferred units was recorded within accrued liabilities 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 will be amortized for the period from issuance of the preferred units through March 13, 2007, and the amortization will be 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 the three months ended March 31, 2006 was $0.1 million. 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. If converted to common units, the preferred equity amount converted will be reclassified to common limited partners equity within Partners Capital on the Partnership s consolidated balance sheet.

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, 2005 through March 31, 2006 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 11, 2005	December 31, 2004	$ 0.72	$ 5,187	$ 1,280
May 13, 2005	March 31, 2005	$ 0.75	$ 5,404	$ 1,500
August 5, 2005	June 30, 2005	$ 0.77	$ 7,319	$ 2,174
November 14, 2005	September 30, 2005	$ 0.81	$ 7,711	$ 2,565
February 14, 2006	December 31, 2005	$ 0.83	$ 10,416	$ 3,638

On April 26, 2006, the Partnership declared a cash distribution of $0.84 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2006. The $14.3 million distribution, including $3.8 million to the General Partner, will be paid on May 15, 2006 to unitholders of record at the close of business on May 9, 2006.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2006	December 31, 2005	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 455,602	$ 443,729	15 40
Rights of way	19,841	19,252	20 40
Buildings	3,482	3,350	40
Furniture and equipment	2,036	1,525	3 7
Other	1,264	889	3 10
	482,225	468,745	
Less accumulated depreciation	(27,743)	(23,679)	
	$ 454,482	$ 445,066	

The Partnership completed the acquisition of a 75% interest in NOARK for approximately $179.8 million in October 2005 (see Note 8). Due to its recent date of acquisition, the purchase price allocation is based upon estimated values, which are subject to adjustment and could change significantly as the Partnership continues to evaluate this preliminary allocation. At March 31, 2006, the portion of the purchase price allocated to property, plant and equipment for NOARK was included within pipelines, processing and compression facilities.

NOTE 7 OTHER ASSETS

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

	March 31, 2006	December 31, 2005
Deferred finance costs, net of accumulated amortization of $2,257 and $1,636 at March 31, 2006 and December 31, 2005, Respectively	$ 14,587	$ 15,034
Security deposits	1,501	1,599
Other		68
	$ 16,088	$ 16,701

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 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 owns a 75% interest in NOARK. NOARK s assets included a Federal Energy Regulatory Commission (FERC)-regulated interstate pipeline and an unregulated natural gas gathering system. The remaining 25% interest in NOARK is owned by Southwestern, a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Total consideration of $179.8 million, including $16.8 million for working capital adjustments and other related transaction costs, was funded through borrowings under the Partnership s credit facility. 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 preliminary purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed, based on their fair values at the date of acquisition (in thousands):

Cash and cash equivalents	$ 16,215
Accounts receivable	11,091
Prepaid expenses	497
Property, plant and equipment	126,238
Other assets	1,515
Intangible assets customer contracts	11,600
Intangible assets customer relationships	15,700
Goodwill	48,843
Total assets acquired	231,699
Accounts payable and accrued liabilities	(12,269)
Total debt	(39,600)
Total liabilities assumed	(51,869)
Net assets acquired	179,830
Less: Cash and cash equivalents acquired	(16,215)
Net cash paid for acquisition	$ 163,615

Due to its recent date of acquisition, the purchase price allocation for NOARK is based upon preliminary data that is subject to adjustment and could change significantly as the Partnership continues to evaluate this allocation. The Partnership recorded goodwill in connection with this acquisition as a result of NOARK s significant cash flow and its strategic industry and geographic position. The Partnership s 75% ownership interest in the results of NOARK s operations are included within its consolidated financial statements from its date of acquisition.

Elk City

In April 2005, the Partnership acquired all of the outstanding equity interests in ETC Oklahoma Pipeline, Ltd. (Elk City), a Texas limited partnership, for $196.0 million, including related transaction costs. Elk City s principal assets included approximately 300 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma, a natural gas processing facility in Elk City, Oklahoma and a gas treatment facility in Prentiss, Oklahoma. The acquisition was accounted for using the purchase method of accounting under 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, based on their fair values at the date of acquisition (in thousands):

Accounts receivable	$ 5,587
Other assets	497
Property, plant and equipment	104,106
Intangible assets customer contracts	12,390
Intangible assets customer relationships	17,260
Goodwill	61,136
Total assets acquired	200,976
Accounts payable and accrued liabilities	(4,970)
Net assets acquired	$ 196,006

The Partnership recorded goodwill in connection with this acquisition as a result of Elk City s significant cash flow and its strategic industry position. Elk City s results of operations are included within the Partnership s consolidated financial statements from its date of acquisition.

The following data presents pro forma revenue and net income for the Partnership as if the acquisitions discussed above, the equity offerings in June 2005 and November 2005 (see Note 3), the issuance of $250.0 million of 8.125% senior notes (see Note 10), and the issuance of the 6.5% cumulative convertible preferred units (see Note 4) had occurred on January 1, 2005. The Partnership has prepared these unaudited pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if the Partnership had completed these acquisitions at the beginning of the periods shown below or the results that will be attained in the future (in thousands, except per unit data):

	Three Months Ended March 31,	
	2006	**2005**
Total revenue and other income	$ 117,810	$ 105,971
Net income	$ 9,499	$ 1,082
Net income attributable to common limited partners and the General Partner	$ 9,018	$ 631
Net income (loss) attributable to common limited partners per unit:		
Basic	$ 0.41	$ (0.05)
Diluted	$ 0.40	$ (0.05)

NOTE 9 DERIVATIVE INSTRUMENTS

The Partnership enters into certain financial swap and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), 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 a fixed price and remits a floating price based on certain indices for the relevant contract period.

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 natural gas futures and options 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 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 income (loss), and reclassifies them to natural gas and liquids revenue within the 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 its consolidated statements of income as they occur. At March 31, 2006 and December 31, 2005, the Partnership reflected net hedging liabilities on its consolidated balance sheets of $28.2

million and $30.4 million, respectively. Of the $27.3 million of net loss in accumulated other comprehensive loss at March 31, 2006, if the fair value of the instruments remain at current market values, the Partnership will reclassify $10.3 million of losses to its consolidated statements of income over the next twelve month period as these contracts expire, and $17.0 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 natural gas and liquids revenue 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 $2.4 million and $0.7 million for the three months ended March 31, 2006 and 2005, respectively, within its consolidated statements of income related to the settlement of qualifying hedge instruments. The Partnership also recognized a gain of $0.5 million and a loss of $0.2 million for the three months ended March 31, 2006 and 2005, respectively, within its consolidated statements of income related to the change in market value of non-qualifying or ineffective hedges.

A portion of the Partnership s future natural gas 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 revenue.

As of March 31, 2006, the Partnership had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability(1) (in thousands)
2006	40,068,000	$ 0.737	$ (7,379)
2007	36,036,000	0.717	(7,220)
2008	33,012,000	0.697	(6,811)
2009	8,568,000	0.746	(1,522)
			$ (22,932)

Natural Gas Fixed Price Swaps

Production Period Ended December 31,	Volumes (MMBTU)(2)	Average Fixed Price (per MMBTU)	Fair Value Liability(3) (in thousands)
2006	3,260,000	$ 7.552	$ 450
2007	1,080,000	7.255	(2,536)
2008	240,000	7.270	(534)
			$ (2,620)

Natural Gas Basis Swaps

Production Period Ended December 31,	Volumes (MMBTU)(2)	Average Fixed Price (per MMBTU)	Fair Value Asset(3) (in thousands)
2006	3,510,000	$ (0.684)	$ (692)
2007	1,080,000	(0.535)	747
2008	240,000	(0.555)	122
			$ 177

Crude Oil Fixed Price Swaps

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability[3] (in thousands)
2006	56,000	$ 52.081	$ (923)
2007	80,400	56.069	(1,097)
2008	62,400	59.267	(596)
2009	36,000	62.700	(178)
			$ (2,794)

Crude Oil Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability[3] (in thousands)	Option Type
2006	6,600	$ 60.000	$	Puts purchased
2006	6,600	73.380		Calls sold
2007	13,200	60.000		Puts purchased
2007	13,200	73.380		Calls sold
2008	17,400	60.000		Puts purchased
2008	17,400	72.807		Calls sold
2009	30,000	60.000		Puts purchased
2009	30,000	71.250		Calls sold
			$	
		Total net liability	$ (28,169)	

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

(2) MMBTU represents million British Thermal Units.

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

NOTE 10 DEBT

Total debt consists of the following (in thousands):

	March 31, 2006	December 31, 2005
Revolving Credit Facility	$	$ 9,500
Senior Notes	250,000	250,000
NOARK Notes	39,000	39,000
Other debt	176	125
	289,176	298,625
Less current maturities	(1,284)	(1,263)
	$ 287,892	$ 297,362

Credit Facility

The Partnership has a $225.0 million credit facility with a syndicate of banks which matures in April 2010. 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). There were no amounts outstanding under the credit facility at March 31, 2006. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $11.1 million was outstanding at March 31, 2006. 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 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 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 5.75 to 1.0, reducing to 4.5 to 1.0 on June 30, 2006 and 4.0 to 1.0 on September 30, 2006; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.75 to 1.0, reducing to 4.5 to 1.0 on June 30, 2006; 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, 2006, the Partnership s ratio of senior secured debt to EBITDA was 0.9 to 1.0, its funded debt ratio was 3.8 to 1.0 and its interest coverage ratio was 4.2 to 1.0.

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

Senior Notes

In December 2005, the Partnership and its subsidiary, Atlas Pipeline Finance Corp., 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. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15, commencing on June 15, 2006. The Senior Notes are redeemable at any time on or after December 15, 2010 at certain redemption prices, together with accrued unpaid interest to the date of redemption. The Senior Notes are also redeemable at any time prior to December 15, 2010 at a make-whole redemption price. 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 for which the net proceeds are not reinvested into the Partnership 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.

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, 2006.

In connection with a Senior Notes registration rights agreement entered into by the Partnership, it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the Senior Notes by April 19, 2006, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission by July 18, 2006, and (c) cause the exchange offer to be consummated by August 17, 2006. If the Partnership does not meet the aforementioned deadlines, the Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the deadlines have been met. On April 19, 2006, the Partnership filed an exchange offer registration statement with the Securities and Exchange Commission for the Senior Notes in satisfaction of one of the requirements of the registration rights agreement noted previously.

NOARK Notes

At March 31, 2006, NOARK s subsidiary, NOARK Pipeline Finance, L.L.C., had $39.0 million in principal amount outstanding of 7.15% notes due in 2018 (see Note 15). The notes are governed by an indenture dated June 1, 1998 for which UMB Bank, N.A. serves as trustee. Interest on the notes is payable semi-annually, in cash, in arrears on June 1 and December 1 of each year. The remaining liability under the notes is allocated severally 100% to Southwestern and is presented as debt on the Partnership s consolidated balance sheet. The notes are subject to semi-annual redemption in installments of $0.6 million, plus accrued and unpaid interest. Additionally, at Southwestern s option, these notes may be redeemed as of a particular payment date at their redemption price plus a make-whole premium and unpaid interest accrued to that date by giving the trustee at least 60 days notice. Under the partnership agreement, payments on the notes will be made from amounts otherwise distributable to Southwestern and, if those amounts are insufficient, Southwestern is required to make a capital contribution to NOARK. NOARK distributes available cash to the partners in accordance with their ownership interests after deduction of their respective portion of amounts payable on the notes.

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.

On March 9, 2004, the Oklahoma Tax Commission (OTC) filed a petition against Spectrum Field Services, Inc. (Spectrum) alleging that Spectrum, prior to its acquisition by the Partnership, underpaid gross production taxes beginning in June 2000. The OTC is seeking a settlement of $5.0 million plus interest and penalties. The Partnership plans on defending itself against this allegation vigorously. In addition, under the terms of the Spectrum purchase agreement, $14.0 million has been placed in escrow to cover the costs of any adverse settlement resulting from the petition and other indemnification obligations of the purchase agreement.

As of March 31, 2006, the Partnership is committed to expend approximately $28.3 million on pipeline extensions, compressor station upgrades and processing facility upgrades, including $14.0 million related to the Sweetwater gas plant, a new cryogenic gas processing plant the Partnership is constructing in Beckham County, Oklahoma. The Partnership expects the plant to be completed in third quarter of 2006.

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 the General Partner s managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units. Only phantom units have been granted under the LTIP through March 31, 2006.

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, 2006, phantom units granted under the LTIP generally had vesting periods of four years. The vesting period may also include the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined in the LTIP. Of the units outstanding under the LTIP at March 31, 2006, 47,959 units will vest within the following twelve months. All units outstanding under the LTIP at March 31, 2006 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs during the three months ended March 31, 2006 and 2005 were $0.1 million for each period and were recorded as reductions of Partners Capital on the consolidated balance sheet.

The Partnership has adopted SFAS No. 123(R), Share-Based Payment, as revised (SFAS No. 123(R)), as of December 31, 2005. 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. Prior to the adoption of SFAS No. 123(R), the Partnership followed Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and its interpretations (APB No. 25), which SFAS No. 123(R) superseded. APB No. 25 allowed for valuation of share-based payments to employees at their intrinsic values. Under this methodology, the Partnership recognized compensation expense for phantom units granted only if the current market price of the underlying units exceeded the exercise price. Since the inception of the LTIP, the Partnership has only granted phantom units with no exercise price and, as such, recognized compensation expense based upon the fair value of the Partnership s limited partner units. Since the Partnership has historically recognized compensation expense for its share-based payments at their fair values, the adoption of SFAS No. 123(R) did not have a material impact on its consolidated financial statements.

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

	Three Months Ended March 31,	
	2006	**2005**
Outstanding, beginning of period	110,128	58,329
Granted[1]	728	66,977
Matured		(105)
Forfeited		(679)
Outstanding, end of period	110,856	124,522
Non-cash compensation expense recognized (in thousands)	$ 523	$ 449

[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 $41.11 per unit and $48.62 per unit for awards granted for the three months ended March 31, 2006 and 2005, respectively.

At March 31, 2006, the Partnership had approximately $2.0 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 Spectrum will vest on September 30, 2007, and awards associated with performance targets of other acquisitions will vest on December 31, 2008.

For the three month period ended March 31, 2006, the Partnership recognized compensation expense of $0.8 million related to the vesting of awards under these incentive compensation agreements, based upon the faire value of the 206,704 common unit awards expected to be issued as of March 31, 2006, which is based upon management s estimate of the probable outcome of the performance targets at that date. No compensation expense was recognized for these awards for the three month period ended March 31, 2005 as management determined that the achievement of these performance targets was not probable at that time. At March 31, 2006, the Partnership had approximately $5.0 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.

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 executive officers, 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 substantially all of their time to activities on the Partnership s behalf. The Partnership reimburses Atlas America at cost for direct costs incurred by them on its 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 $0.7 million and $0.5 million for the three months ended March 31, 2006 and 2005, respectively, for compensation and benefits related to their executive officers. For the three months ended March 31, 2006 and 2005, direct reimbursements were $6.5 million and $4.3 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 America, Atlas America 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 America 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 business 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 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.

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

	Three Months Ended March 31,	
	2006	**2005**
Mid-Continent		
Revenue:		
Natural gas and liquids	$ 101,017	$ 42,334
Transportation and compression	8,750	
Interest income and other	1	(14)
Total revenue and other income	109,768	42,320
Costs and expenses:		
Natural gas and liquids	85,892	35,459
Plant operating	3,227	1,204
Transportation and compression	1,354	
General and administrative	2,922	751
Minority interest in NOARK	569	
Depreciation and amortization	4,459	1,355
Total costs and expenses	98,423	38,769
Segment profit	$ 11,345	$ 3,551
Appalachia		
Revenue:		
Transportation and compression affiliates	$ 7,874	$ 4,847
Transportation and compression third parties	27	15
Interest income and other	141	95
Total revenue and other income	8,042	4,957
Costs and expenses:		
Transportation and compression	968	676
General and administrative	884	868
Depreciation and amortization	816	574
Total costs and expenses	2,668	2,118
Segment profit	$ 5,374	$ 2,839

Reconciliation of segment profit to net income		
Segment profit:		
Mid-Continent	$ 11,345	$ 3,551
Appalachia	5,374	2,839
Total segment profit	16,719	6,390
Corporate general and administrative expenses	(883)	(869)
Interest expense	(6,337)	(1,135)
Other		(136)
Net income	$ 9,499	$ 4,250
Capital Expenditures:		
Mid-Continent	$ 9,420	$ 3,734
Appalachia	4,142	2,343
	$ 13,562	$ 6,077

	March 31, 2006	December 31, 2005
Balance sheet		
Total assets:		
Mid-Continent	$ 661,560	$ 668,782
Appalachia	40,931	43,428
Corporate other	37,446	30,516
	$ 739,937	$ 742,726
Goodwill:		
Mid-Continent	$ 108,327	$ 109,141
Appalachia	2,305	2,305
	$ 110,632	$ 111,446

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

	Three Months Ended March 31, 2006	2005
Natural gas and liquids:		
Natural gas	$ 57,514	$ 23,657
NGLs	37,948	17,384
Condensate	1,322	727
Other [(1)]	4,233	566
Total	$ 101,017	$ 42,334
Transportation and compression:		
Affiliates	$ 7,874	$ 4,847
Third parties	8,777	15
Total	$ 16,651	$ 4,862

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

NOTE 15 SUBSEQUENT EVENTS

On May 2, 2006, the Partnership acquired the remaining 25% equity ownership interest in NOARK from Southwestern. Prior to this transaction, the Partnership owned a 75% equity ownership interest in NOARK, which was acquired in October 2005 from Enogex, Inc. Total consideration for the acquisition of $65.5 million, net of approximately $3.5 million for working capital purposes, was funded through borrowings under the Partnership s credit facility. In connection with this acquisition, Southwestern Energy Company acquired the issuer of the NOARK notes and agreed to retain the obligation for the outstanding NOARK notes, with the result that neither NOARK nor the Partnership have any further liability under them.

On May 4, 2006, the Partnership announced the pricing of $35.0 million of additional senior unsecured notes due 2015 in a private placement at 103% of par for net proceeds of $36.6 million, including accrued interest and net of initial purchaser s discount and other transaction costs. The Partnership intends to use the net proceeds from the private placement to partially repay borrowings under its credit facility made in connection with the recent acquisition of the remaining 25% interest in NOARK.

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

Forward-Looking Statements

When used in this Form 10-Q, the words believes, anticipates, expects and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 1A, under the caption Risk Factors , in our annual report on Form 10-K for 2005. 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. We were formed in May 1999 to acquire, own and operate natural gas gathering systems previously owned by Atlas America, Inc. and its affiliates (Atlas America), a publicly traded company (NASDAQ: ATLS). 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. Our principal business objective is to generate cash for distribution to our unitholders.

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

a 75% interest in a FERC-regulated, 565-mile interstate pipeline system, that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and has throughput capacity of approximately 322 MMcf/d;

two natural gas processing plants with aggregate capacity of approximately 230 MMcf/d and one treating facility with a capacity of approximately 200 MMcf/d, all located in Oklahoma; and

1,765 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 its natural gas processing plants or Ozark Gas Transmission.

Through our Appalachian operations, we own and operate 1,500 miles of intrastate 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, the parent of our general partner and a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin, we gather substantially all of the natural gas for our Appalachian operations from wells operated by Atlas America.

Significant Acquisitions

Since our initial public offering in January 2000 through March 31, 2006, we have completed five acquisitions at an aggregate cost of approximately $521.1 million, including, most recently:

In October 2005, we acquired from Enogex, a wholly-owned subsidiary of OGE Energy Corp., all of the outstanding equity of Atlas Arkansas, which owns a 75% 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. The remaining 25% interest in NOARK is owned by Southwestern.

In April 2005, we acquired all of the outstanding equity interests of Elk City for $196.0 million, including related transaction costs. Elk City s principal assets include approximately 300 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma and the Texas panhandle, a natural gas processing facility in Elk City, Oklahoma, with a total capacity of approximately 200 MMcf/d and a gas treatment facility in Prentiss, Oklahoma, with a total capacity of approximately 200 MMcf/d.

Recent Developments

On May 2, 2006, we acquired the remaining 25% equity ownership interest in NOARK from Southwestern. Prior to this transaction, we owned a 75% equity ownership interest in NOARK, which was acquired in October 2005 from Enogex, Inc. Total consideration for the acquisition of $65.5 million, net of approximately $3.5 million for working capital purposes, was funded through borrowings under our credit facility. In connection with this acquisition, Southwestern Energy Company acquired the issuer of the NOARK notes and agreed to retain the obligation for the outstanding NOARK notes, with the result that neither we nor NOARK have any further liability under them.

On May 4, 2006, we announced the pricing of $35.0 million of additional senior unsecured notes due 2015 in a private placement at 103% of par for net proceeds of $36.6 million, including accrued interest and net of initial purchaser s discount and other transaction costs. We intend to use the net proceeds from the private placement to partially repay borrowings under our credit facility made in connection with the recent acquisition of the remaining 25% interest in NOARK.

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 Appalachia, substantially all of the natural gas we transport is for Atlas America 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 gas subject, in most cases, to a minimum of $0.35 or $0.45 per thousand cubic feet, or mcf, depending upon the ownership of the well. Since our inception in January 2000, our Appalachian transportation fee has always exceeded this minimum in general. The balance of the Appalachian 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 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 gas that we gather and process and is not directly dependent on the value of the natural gas.

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

Keep-Whole Contracts. These contracts require us, as the processor, to 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, since the gas received by the Elk City 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 gas can be bypassed around the Elk City processing plant 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. Our profitability is positively influenced by increases in natural gas and NGL prices and negatively influenced if such prices decrease. 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, 2007 of approximately $2.3 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, 2006	Three Months Ended March 31, 2005
Operating data:		
Appalachia:		
Average throughput volumes (Mcf/d)	57,326	52,371
Average transportation rate per Mcf	$ 1.53	$ 1.03
Mid-Continent:		
Velma system:		
Gathered gas volume (Mcf/d)	60,715	64,956
Processed gas volume (Mcf/d)	58,528	62,985
Residue gas volume (Mcf/d)	45,754	49,982
NGL production (Bbl/d)	6,334	6,404
Condensate volume (Bbl/d)	186	234
Elk City system:		
Gathered gas volume (Mcf/d)	252,190	
Processed gas volume (Mcf/d)	130,955	
Residue gas volume (Mcf/d)	119,016	
NGL production (Bbl/d)	5,758	
Condensate volume (Bbl/d)	171	
NOARK system:		
Average throughput volume (Mcf/d)	239,151	

Three Months Ended March 31, 2006 Compared to Three Months Ended March 31, 2005

Revenue. Natural gas and liquids revenue was $101.0 million for the three months ended March 31, 2006, an increase of $58.7 million from $42.3 million for the three months ended March 31, 2005. The increase was attributable to revenue contributions from the NOARK system acquired in October 2005 of $16.9 million and the Elk City system acquired in April 2005 of $39.4 million, and an increase in Velma natural gas and liquids revenue of $2.4 million due to higher commodity prices. Gross natural gas gathered averaged 60.7 MMcf/d on the Velma system for the three months ended March 31, 2006, a decrease of 6.5% from the comparable prior year period due to a decline in low margin volume. Gross natural gas gathered on the Elk City system averaged 252.2 MMcf/d for the three month period ended March 31, 2006. For the NOARK system, average throughput volume was 239.2 MMcf/d for the three months ended March 31, 2006.

Transportation and compression revenue increased to $16.7 million for the three months ended March 31, 2006 from $4.9 million for the comparable prior year period. This $11.8 million increase was primarily due to contributions from the transportation revenues associated with the NOARK system acquired in October 2005 of $7.6 million and the Elk City system acquired in April 2005 of $1.1 million and increases in the Appalachia average transportation rate earned and volume of natural gas transported. Our Appalachia average transportation rate was $1.53 per Mcf for the three months ended March 31, 2006 as compared with $1.03 per Mcf for the prior year three month period, an increase of $0.50 per Mcf. Appalachia s average throughput volume was 57.3 MMcf/d for the three months ended March 31, 2006 as compared with 52.4 MMcf/d for the three months ended March 31, 2005, an increase of 4.9 MMcf/d. The increase in the Appalachia average daily throughput volume was principally due to new wells connected to our gathering system and the completion of a capacity expansion project in 2005 on certain sections of our pipeline system.

Costs and Expenses. Natural gas and liquids cost of goods sold of $85.9 million and plant operating expenses of $3.2 million for the three months ended March 31, 2006 represented increases of $50.4 million and $2.0 million, respectively, from the comparable prior year amounts due primarily to contributions from the acquisitions and an increase in commodity prices. Transportation and compression expenses increased $1.6 million to $2.3 million for the three months ended March 31, 2006 due mainly to NOARK system operating costs and higher Appalachia operating costs as a result of compressors added during 2005 in connection with our capacity expansion project and higher maintenance expense as a result of additional wells connected to our gathering system.

General and administrative expenses, including amounts reimbursed to affiliates, increased $2.2 million to $4.7 million for the three months ended March 31, 2006 compared with $2.5 million for the prior year comparable period. This increase was mainly due to a $0.9 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 acquisitions and capital raising opportunities.

Depreciation and amortization increased to $5.3 million for the three months ended March 31, 2006 compared with $1.9 million for the three months ended March 31, 2005 due primarily to the depreciation and amortization associated with the Elk City and NOARK assets acquired during 2005.

Interest expense increased to $6.3 million for the three months ended March 31, 2006 as compared with $1.1 million for the comparable prior year period. This $5.2 million increase was primarily due to interest associated with our December 2005 issuance of $250.0 million 10-year senior unsecured notes, $0.7 million of interest associated with the NOARK notes, and a $0.4 million increase in amortization of deferred financing costs, partially offset by a decrease in interest associated with borrowings under the credit facility.

Minority interest in NOARK of $0.6 million for the three months ended March 31, 2006 represents Southwestern s 25% ownership interest in the net income of NOARK for the period. Our financial results include the consolidated financial statements of NOARK.

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, 2006, we had no amounts outstanding under our credit facility and $11.1 million of outstanding letters of credit which are not reflected as borrowings on our consolidated balance sheet, with $213.9 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 $372.7 million remains available at March 31, 2006. At March 31, 2006, we had a working capital position of $28.1 million compared with $16.8 million at December 31, 2005. We believe that we have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, unitholder distributions, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cashflow. 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, 2006 Compared to Three Months Ended March 31, 2005

Net cash provided by operating activities of $10.1 million for the three months ended March 31, 2006 increased $3.2 million from $6.9 million for the comparable prior year period. The increase is derived principally from increases in net income attributable to common limited partners and the general partner of $5.2 million, depreciation and amortization of $3.3 million, $0.6 million of minority interest in NOARK during the current period, non-cash compensation expense of $0.9 million, and amortization of deferred financing costs of $0.4 million. These amounts were partially offset by a $7.8 million decrease in cash resulting from changes in the components of working capital. The increases in net income attributable to common limited partners and the general partner, depreciation and amortization and minority interest in NOARK were principally due to the contribution from the acquisitions of Elk City in April 2005 and NOARK in October 2005.

Net cash used in investing activities was $13.6 million for the three months ended March 31, 2006, an increase of $6.5 million from $7.0 million for the comparable prior year period. This increase was principally due to a $7.5 million increase in capital expenditures. See further discussion of capital expenditures under Capital Requirements.

Net cash provided by financing activities was $7.0 million for the three months ended March 31, 2006, an increase of $15.4 million from $8.4 million of net cash used in financing activities for the comparable prior year period. This increase was principally due to the $30.0 million of net proceeds from the issuance of our cumulative convertible preferred units in March 2006, partially offset by a $8.9 million increase in net repayments under our credit facility and an increase of $7.6 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.

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, 2006	Three Months Ended March 31, 2005
Maintenance capital expenditures	$ 1,161	$ 392
Expansion capital expenditures	12,401	5,685
Total	$ 13,562	$ 6,077

Expansion capital expenditures increased to $12.4 million for the three months ended March 31, 2006, due principally to expansions of the Appalachia, Velma and Elk City gathering systems, processing facilities and compressor upgrades to accommodate new wells drilled in our service areas. Expansion capital expenditures for our Mid-Continent region also include approximately $1.1 million of costs incurred related to the construction of the Sweetwater gas plant, a new natural gas processing plant in Oklahoma expected to be operational in the third quarter of 2006 (see Significant Announced Internal Growth Project). As of March 31, 2006, we have incurred $11.9 million of the projected $40 million in expenditures related to the Sweetwater project. Maintenance capital expenditures for the three months ended March 31, 2006 increased to $1.2 million compared with the prior year comparable period due to fluctuations in the timing of scheduled maintenance activity and the additional maintenance requirements of the 2005 acquisitions. As of March 31, 2006, we are committed to expend approximately $28.3 million on pipeline extensions, compressor station upgrades and processing facility upgrades, including $14.0 million related to the Sweetwater gas plant.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash to our partners 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 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 unitholders 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 for three months ended March 31, 2006 was $3.5 million.

Common Equity Offerings

In November 2005, we sold 2,700,000 of our common units in a public offering for gross proceeds of $113.4 million. In addition, pursuant to an option granted to the underwriters of the offering, we sold an additional 330,000 common units in December 2005 for gross proceeds of $13.9 million, resulting in aggregate total gross proceeds of $127.3 million. The units, which were issued under our previously filed shelf registration statement, resulted in total net proceeds of approximately $121.0 million, after underwriting commissions and other transaction costs. We primarily utilized the net proceeds from the sale to repay a portion of the amounts due under our credit facility.

In June 2005, we sold 2,300,000 common units in a public offering for total gross proceeds of $96.5 million. The units, which were issued under our previously filed shelf registration statement, resulted in net proceeds of approximately $91.7 million, after underwriting commissions and other transaction costs. We primarily utilized the net proceeds from the sale to repay a portion of the amounts due under our credit facility.

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, 2006, $372.7 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 sold 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC, an affiliate of Elliott & Associates, for aggregate proceeds of $30.0 million. We have the right, subject to specified conditions, before June 11, 2006, to require Sunlight Capital Partners to purchase an additional 10,000 preferred units on the same terms. 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 also agreed to file a registration statement to cover the resale of the common units underlying the preferred units. The net proceeds from the issuance of the preferred units will be used to fund a portion of our capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. 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 any 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.

Credit Facility

We have a $225.0 million credit facility with a syndicate of banks which matures in April 2010. 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). There were no amounts outstanding under the credit facility at March 31, 2006. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $11.1 million was outstanding at March 31, 2006. 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.

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 5.75 to 1.0, reducing to 4.5 to 1.0 on June 30, 2006 and 4.0 to 1.0 on September 30, 2006; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.75 to 1.0, reducing to 4.5 to 1.0 on June 30, 2006; 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, 2006, our ratio of senior secured debt to EBITDA was 0.9 to 1.0, our funded debt ratio was 3.8 to 1.0 and our interest coverage ratio was 4.2 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., 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. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15, commencing on June 15, 2006. 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 a make-whole redemption price. 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.

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 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, 2006.

In connection with a Senior Notes registration rights agreement entered into by us, we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the Senior Notes by April 19, 2006, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission by July 18, 2006, and (c) cause the exchange offer to be consummated by August 17, 2006. If we do not meet the aforementioned deadlines, the Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the deadlines have been met. On April 19, 2006, we filed an exchange offer registration statement with the Securities and Exchange Commission for the Senior Notes in satisfaction of one of the requirements of the registration rights agreement noted previously.

NOARK Notes

At March 31, 2006, NOARK s subsidiary, NOARK Pipeline Finance, L.L.C., had $39.0 million in principal amount outstanding of 7.15% notes due in 2018 (see Recent Developments). The notes are governed by an indenture dated June 1, 1998 for which UMB Bank, N.A. serves as trustee. Interest on the notes is payable semi-annually, in cash, in arrears on June 1 and December 1 of each year. The remaining liability under the notes is allocated severally 100% to Southwestern and is presented as debt on our consolidated balance sheet. The notes are subject to a semi-annual redemption in installments of $0.6 million, plus accrued and unpaid interest. Additionally, at Southwestern s option, these notes may be redeemed as of a particular payment date at their redemption price plus a make-whole premium and unpaid interest accrued to that date by giving the trustee at least 60 days notice. Under the partnership agreement, payments on the notes will be made from amounts otherwise distributable to Southwestern and, if those amounts are insufficient, Southwestern is required to make a capital contribution to NOARK. NOARK distributes available cash to the partners in accordance with their ownership interests after deduction of their respective portion of amounts payable on the notes.

Significant Announced Internal Growth Project

In October 2005, we announced plans to complete construction of a new natural gas processing plant in Beckham County, Oklahoma near our Prentiss treating facility, in the third quarter of 2006. The new plant, to be known as the Sweetwater gas plant, will be scaled to 120 MMcf/d of processing capacity. The Sweetwater gas plant will be located west of our Elk City gas plant, and is being built to further access natural gas production actively being developed in western Oklahoma and the Texas panhandle. Along with the Sweetwater gas plant, we will construct a gathering system to be located primarily in western Oklahoma and in the Texas panhandle, more specifically, Beckham and Roger Mills counties in Oklahoma and Hemphill County, Texas. We anticipate that construction of the Sweetwater gas plant and associated gathering system will cost approximately $40.0 million.

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, 2005, and there have been no material changes to these policies through March 31, 2006.

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-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 periodically use 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, 2006. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

Interest Rate Risk. At March 31, 2006, we had a $225.0 million revolving credit facility (no amounts outstanding) to fund the expansion of our existing gathering systems, acquire other natural gas gathering systems and fund working capital movements as needed. Borrowings under this credit facility in future periods will subject us to movements in interest rates, which could negatively impact our net income and cash flow.

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 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, 2007 of approximately $2.3 million.

We enter into certain financial swap and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133 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 a fixed price and remit a floating price based on certain indices for the relevant contract period.

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 our consolidated statements of income.

Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. For derivatives qualifying as the effective portion of changes in fair value in partners capital as accumulated other comprehensive loss and reclassify them to natural gas and liquids revenue within the 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 our consolidated statements of income as they occur. At March 31, 2006 and December 31, 2005, we reflected net hedging liabilities on our consolidated balance sheets of $28.2 million and $30.4 million, respectively. Of the $27.3 million of net loss in accumulated other comprehensive loss at March 31, 2006, if the fair value of the instruments remain at current market values, we will reclassify $10.3 million of losses to our consolidated statements of income over the next twelve month period as these contracts expire, and $17.0 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 natural gas and liquids revenue 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 $2.4 million and $0.7 million for the three months ended March 31, 2006 and 2005, respectively, within our consolidated statements of income related to the settlement of qualifying hedge instruments. We also recognized a gain of $0.5 million and a loss of $0.2 million for the three months ended March 31, 2006 and 2005, respectively, within our consolidated statements of income related to the change in market value of non-qualifying or ineffective hedges.

A portion of our future natural gas 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 revenue.

As of March 31, 2006, we had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability(1) (in thousands)
2006	40,068,000	$ 0.737	$ (7,379)
2007	36,036,000	0.717	(7,220)
2008	33,012,000	0.697	(6,811)
2009	8,568,000	0.746	(1,522)
			$ (22,932)

Natural Gas Fixed Price Swaps

Production Period Ended December 31,	Volumes (MMBTU)(2)	Average Fixed Price (per MMBTU)	Fair Value Liability(3) (in thousands)
2006	3,260,000	$ 7.552	$ 450
2007	1,080,000	7.255	(2,536)
2008	240,000	7.270	(534)
			$ (2,620)

Natural Gas Basis Swaps

Production Period Ended December 31,	Volumes (MMBTU)(2)	Average Fixed Price (per MMBTU)	Fair Value Asset(3) (in thousands)
2006	3,510,000	$ (0.684)	$ (692)
2007	1,080,000	(0.535)	747

2008	240,000	(0.555)	122
			$ 177

Crude Oil Fixed Price Swaps

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability[3] (in thousands)
2006	56,000	$ 52.081	$ (923)
2007	80,400	56.069	(1,097)
2008	62,400	59.267	(596)
2009	36,000	62.700	(178)
			$ (2,794)

Crude Oil Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability[3] (in thousands)	Option Type
2006	6,600	$ 60.000	$	Puts purchased
2006	6,600	73.380		Calls sold
2007	13,200	60.000		Puts purchased
2007	13,200	73.380		Calls sold
2008	17,400	60.000		Puts purchased
2008	17,400	72.807		Calls sold
2009	30,000	60.000		Puts purchased
2009	30,000	71.250		Calls sold
			$	
		Total net liability	$ (28,169)	

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

(2) MMBTU represents million British Thermal Units.

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

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.

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None.

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)
3.3	Certificate of Designation of 6.5% Cumulative Convertible Preferred Units (3)
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)
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.

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 5, 2006	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 5, 2005	By:	/s/ MICHAEL L. STAINES Michael L. Staines President, Chief Operating Officer and Managing Board Member of the General Partner
Date: May 5, 2005	By:	/s/ MATTHEW A. JONES Matthew A. Jones Chief Financial Officer of the General Partner
Date: May 5, 2005	By:	/s/ SEAN P. MCGRATH Sean P. McGrath Chief Accounting Officer of the General Partner