UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A

Amendment No.1

(Mark One)

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

For the quarterly period ended September 30, 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	**(I.R.S. Employer**
of incorporation or organization)	**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

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Explanatory Note

We are filing this Amendment No.1 to our Quarterly Report on Form 10-Q (Amendment No.1) for the quarter ended September 30, 2006. The Quarterly Report on Form 10-Q was originally filed on November 9, 2006 (the Original Filing). Amendment No. 1 is being filed to recognize additional net income of $2.3 million within our consolidated financial statements for both the three and nine months ended September 30, 2006. The additional net income is the result of the recognition of a gain with respect to certain financial hedge instruments under Statement of Financial Accounting Standards No. 133, Accounting for derivative Instruments and Hedging Activities. Amendment No. 1 amends Items 1 and 2 of Part I of the Original Filing to reflect the effects of this net income recognition and for the convenience of the reader, sets forth the remainder of the Original Filing in its entirety.

Except as described above, no other information in Amendment No. 1 is amended hereby. Amendment No. 1 does not reflect events occurring after the filing of the Original Filing or modify or update those disclosures affected by subsequent events. Accordingly, Amendment No. 1 should be read in conjunction with our other filings made with the SEC subsequent to the filing of the Original Filing. In addition, Item 6 of Part II of Amendment No. 1 has been amended to contain, in accordance with the rules of the SEC, currently-dated certifications from our Chief Executive Officer and Chief Financial Officer. The certifications of our Chief Executive Officer and Chief Financial Officer are attached to Amendment No. 1 as Exhibits 31.1, 31.2, 32.1 and 32.2, respectively.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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ON FORM 10-Q/A

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS (RESTATED)

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

C ONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	September 30, 2006 (As Restated - see Note 15)	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,986	$ 34,237
Accounts receivable affiliates	6,648	4,649
Accounts receivable	46,325	57,528
Current portion of hedge asset	3,626	11,388
Prepaid expenses and other	7,404	2,454
Total current assets	71,989	110,256
Property, plant and equipment, net	590,634	445,066
Long-term hedge asset	4,975	4,388
Intangible assets, net	26,133	54,869
Goodwill	63,441	111,446
Other assets, net	14,648	16,701
	$ 771,820	$ 742,726
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 92	$ 1,263
Accounts payable	5,092	15,609
Accrued liabilities	23,594	16,064
Current portion of hedge liability	17,431	23,796
Accrued producer liabilities	29,748	36,712
Total current liabilities	75,957	93,444
Long-term hedge liability	18,910	22,410
Long-term debt, less current portion	299,548	297,362
Commitments and contingencies		
Partners capital:		
Preferred limited partner s interest	38,770	
Common limited partners interests	356,975	349,491
General partner s interest	11,152	10,094

Accumulated other comprehensive loss		(29,492)		(30,075)
Total partners capital		377,405		329,510
	$	771,820	$	742,726

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30, 2006 (As Restated - see Note 15)	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006 (As Restated - see Note 15)	Nine Months Ended September 30, 2005
Revenue:				
Natural gas and liquids	$ 103,671	$ 96,234	$ 300,694	$ 218,268
Transportation and compression affiliates	6,951	6,248	22,659	16,447
Transportation and compression third parties	6,726	16	20,882	54
Interest income and other	3,198	147	3,622	352
Total revenue and other income	120,546	102,645	347,857	235,121
Costs and expenses:				
Natural gas and liquids	89,679	82,537	252,577	184,578
Plant operating	3,853	2,745	11,006	7,242
Transportation and compression	2,948	871	8,404	2,169
General and administrative	4,835	2,431	12,700	7,763
Compensation reimbursement affiliates	378	412	1,983	1,365
Depreciation and amortization	6,152	3,438	16,685	8,495
Interest	5,700	3,166	18,191	8,478
Minority interest in NOARK			118	
Other		(9)		138
Total costs and expenses	113,545	95,591	321,664	220,228
Net income	7,001	7,054	26,193	14,893
Preferred unit imputed dividend cost	(627)		(1,262)	
Net income attributable to common limited partners and the general partner	$ 6,374	$ 7,054	$ 24,931	$ 14,893
Allocation of net income attributable to common limited partners and the general partner:				
Common limited partners interest	$ 2,567	$ 4,600	$ 13,664	$ 9,003
General partner s interest	3,807	2,454	11,267	5,890
Net income attributable to common limited partners and the general partner	$ 6,374	$ 7,054	$ 24,931	$ 14,893
Net income attributable to common limited partners per unit:				
Basic	$ 0.20	$ 0.48	$ 1.07	$ 1.09

Diluted	$ 0.19	$ 0.48	$ 1.05	$ 1.09
Weighted average common limited partner units outstanding:				
Basic	13,076	9,511	12,818	8,226
Diluted	13,248	9,591	12,975	8,277

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL (AS RESTATED-SEE NOTE 15)

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2006

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units		Preferred Limited Partner	Common Limited Partners	General Partners	Accumulated Other Comprehensive Income/(Loss)	Total Partners Capital
	Preferred	Common					
Balance at January 1, 2006		12,549,266	$	$ 349,491	$ 10,094	$ (30,075)	$ 329,510
Issuance of common units		500,000		19,704			19,704
Issuance of 6.5% cumulative convertible preferred limited partner units	40,000		37,508				37,508
Preferred dividend discount				2,350	48		2,398
General partner capital contribution					1,206		1,206
Unissued common units under incentive plans				4,125			4,125
Issuance of units under incentive plans		31,152					
Distributions paid to common limited partners and the general partner				(32,076)	(11,463)		(43,539)
Distribution equivalent rights paid on unissued units under incentive plans				(283)			(283)
Other comprehensive income						583	583
Net income			1,262	13,664	11,267		26,193
Balance at September 30, 2006	40,000	13,080,418	$ 38,770	$ 356,975	$ 11,152	$ (29,492)	$ 377,405

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Nine Months Ended September 30, 2006 (As Restated - see Note 15)	Nine Months Ended September 30, 2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 26,193	$ 14,893
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	16,685	8,495
Non-cash gain on derivative value	(2,107)	(1,091)
Non-cash compensation expense	4,125	2,809
Amortization of deferred finance costs	1,753	1,741
Minority interest in NOARK	118	
Gain on asset sales and dispositions	(2,639)	
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable and prepaid expenses and other	7,434	(22,317)
Accounts payable and accrued liabilities	(9,648)	25,511
Accounts payable and accounts receivable affiliates	(1,999)	(2,922)
Net cash provided by operating activities	39,915	27,119
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net cash paid for acquisitions	(30,000)	(195,201)
Capital expenditures	(61,743)	(34,519)
Proceeds from sales of assets	7,559	
Other	67	(172)
Net cash used in investing activities	(84,117)	(229,892)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from issuance of debt	36,610	
Repayment of debt	(38,990)	
Borrowings under credit facility	37,000	271,500
Repayments under credit facility	(33,000)	(142,250)
Net proceeds from issuance of common limited partner units	19,704	91,720
Net proceeds from issuance of preferred limited partner units	39,906	
General partner capital contribution	1,206	1,930
Distributions paid to common limited partners and the general partner	(43,539)	(22,864)
Other	(946)	(3,442)
Net cash provided by financing activities	17,951	196,594
Net change in cash and cash equivalents	(26,251)	(6,179)
Cash and cash equivalents, beginning of period	34,237	18,214

Cash and cash equivalents, end of period	$ 7,986	$ 12,035

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

SEPTEMBER 30, 2006

(Unaudited)

NOTE 1 - BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded Delaware limited partnership formed 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 (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 September 30, 2006, the Partnership had 13,080,418 common limited partnership units, including 1,641,026 unregistered common units held by the General Partner, and 40,000 $1,000 par value cumulative convertible preferred limited partnership units outstanding (see Note 4).

On July 26, 2006, Atlas America contributed its ownership interests in the General Partner to Atlas Pipeline Holdings, L.P. (NYSE: AHD), a then wholly-owned subsidiary of Atlas America. Concurrent with this transaction, Atlas Pipeline Holdings, L.P. issued 3,600,000 common units, representing a 17.1% ownership interest, in an initial public offering at a price of $23.00 per unit. Net proceeds from this offering were distributed to Atlas America.

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 and nine month period ended September 30, 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. During June 2006, the Partnership identified measurement reporting inaccuracies on three newly installed pipeline meters. To adjust for such inaccuracies, which relate to natural gas volume gathered during the third and fourth quarters of 2005 and first quarter of 2006, the Partnership recorded an adjustment of $1.2 million during the second quarter of 2006 to increase natural gas and liquids cost of goods sold. If the $1.2 million adjustment had been recorded when the inaccuracies arose, reported net income would have been reduced by approximately 2.7%, 8.3% and 1.4% for the third quarter of 2005, fourth quarter of 2005, and first quarter of 2006, respectively. Management of the Partnership believes that the impact of these adjustments is immaterial to its current and prior financial statements.

In August 2006, the Partnership sustained fire damage to a compressor station within the Velma region of its Mid-Continent segment. The Partnership maintains property damage and business interruption

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insurance for all of its assets and operating activities. At September 30, 2006, the Partnership has recorded $1.2 million in prepaid expenses and other within its consolidated balance sheet for the estimated net book value of the assets damaged as a result of the incident, which are expected to be recoverable through cash proceeds received from its insurance coverage. Upon receipt of the insurance cash proceeds related to the incident, the Partnership expects to recognize a gain on disposition of these assets, including the write-down of their net book value.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (RESTATED)

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 subsidiaries. The General Partner s interest in the Operating Partnership is reported as part of its overall 2% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

The consolidated financial statements also include the financial statements of NOARK Pipeline System, Limited Partnership (NOARK), an entity in which the Partnership currently owns a 100% operating interest (see Note 8). On May 2, 2006, the Partnership acquired the remaining 25% equity ownership interest in NOARK from Southwestern Energy Pipeline Company (Southwestern), a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN). Prior to this transaction, the Partnership owned a 75% equity ownership interest in NOARK, which it had acquired in October 2005 from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE). In connection with the acquisition of the remaining 25% ownership interest, Southwestern assumed liability for $39.0 million in principal amount outstanding of 7.15% notes due in 2018, which had been presented as long-term debt on the Partnership s consolidated balance sheet prior to the acquisition of the remaining 25% ownership interest. The Partnership now consolidates 100% of NOARK s financial statements. The minority interest expense reflected on the Partnership s consolidated statements of income represents Southwestern s interest in NOARK s net income prior to the May 2, 2006 acquisition.

Use of Estimates

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

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented for the three and nine months ended September 30, 2006 represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

Net Income Per Common Unit

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Weighted average number of common limited partner units basic	13,076	9,511	12,818	8,226
Add: effect of dilutive unit incentive awards	172	80	157	51
Weighted average number of common limited partner units diluted	13,248	9,591	12,975	8,277

For the three and nine months ended September 30, 2006, potential common limited partner units issuable upon conversion of the Partnership s 40,000 $1,000 par value cumulative convertible preferred limited partner units were excluded from the computation of diluted net income attributable to common limited partners as the impact of the conversion would be anti-dilutive (see Note 4 for additional information regarding the conversion features of the preferred limited partner units).

Comprehensive Income (Loss) ***(Restated)***

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006 (Restated)	2005	2006 (Restated)	2005
Net income	$ 7,001	$ 7,054	$ 26,193	$ 14,893
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as hedges	8,536	(29,622)	(9,935)	(49,507)
Add: reclassification adjustment for losses in net income	4,896	2,450	10,518	4,381
Total other comprehensive income (loss)	13,432	(27,172)	583	(45,126)
Comprehensive income (loss)	$ 20,433	$ (20,118)	$ 26,776	$ (30,233)

Revenue Recognition

Revenue in the Appalachia segment is 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 revenue in the Appalachia segment is 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 September 30, 2006 and December 31, 2005 of $29.6 million and $48.4 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 8.1% for both the three and nine months ended September 30, 2006, and the amount of interest capitalized was $1.0 million and $1.9 million for the three and nine months ended September 30, 2006, respectively. There were no interest amounts capitalized for the three and nine months ended September 30, 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 September 30, 2006 and December 31, 2005 (in thousands):

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	September 30, 2006	December 31, 2005	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,390	$ 23,990	8
Customer relationships	17,260	32,960	20
	$ 29,650	$ 56,950	
Accumulated Amortization:			
Customer contracts	$ (2,259)	$ (1,339)	
Customer relationships	(1,258)	(742)	
	$ (3,517)	$ (2,081)	
Net Carrying Amount:			
Customer contracts	$ 10,131	$ 22,651	
Customer relationships	16,002	32,218	
	$ 26,133	$ 54,869	

Certain amounts included within the intangible asset categories are based upon the preliminary purchase price allocation for NOARK. During the third quarter of 2006, the Partnership adjusted the preliminary purchase price allocation and reduced the estimated amount allocated to customer contracts and customer relationships based upon the preliminary findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6). The NOARK purchase price allocation remains subject to further adjustment and could change significantly as the Partnership continues to complete its evaluation.

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 $(0.9) million and $1.4 million for the three and nine months ended September 30, 2006, respectively, which reflects the impact of the adjustment of the preliminary NOARK purchase price allocation. Amortization expense on intangible assets was $0.5 million during the three and nine months ended September 30, 2005. Amortization expense related to intangible assets is estimated to be $2.4 million for each of the next five calendar years commencing in 2007.

Goodwill

At September 30, 2006 and December 31, 2005, the Partnership had $63.4 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 nine months ended September 30, 2006 and 2005 were as follows (in thousands):

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	Nine Months Ended September 30, 2006	2005
Balance, beginning of period	$ 111,446	$ 2,305
Goodwill acquired (preliminary allocation) Elk City acquisition		77,896
Goodwill acquired (preliminary allocation) remaining 25% interest in NOARK	30,195	
Reduction in minority interest deficit acquired	(118)	
Purchase price allocation adjustment NOARK	(78,082)	
Balance, end of period	$ 63,441	$ 80,201

During the third quarter of 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to goodwill based upon the preliminary findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6). The Partnership tests its goodwill for impairment at each year end by comparing enterprise fair values to carrying values. The evaluation of impairment under SFAS No. 142, 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 September 30, 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.

New Accounting Standard

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 provides guidance on quantifying and evaluating the materiality of unrecorded misstatements. The SEC staff recommends that misstatements should be quantified using both a balance sheet and income statement approach and a determination be made as to whether either approach results in quantifying a misstatement which the registrant, after evaluating all relevant factors, considers material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct misstatements occurring in prior years that previously had been considered immaterial based on the appropriate use of the registrant s methodology. SAB 108 is effective for fiscal years ending on or after November 15, 2006. The Partnership does not currently expect SAB 108 to have a material impact on its consolidated financial position or results of operations.

NOTE 3 COMMON UNIT EQUITY OFFERINGS

On May 12, 2006, the Partnership sold 500,000 common units to Wachovia Securities, which then offered the common units to public investors. The units, which were issued under the Partnership s previously filed shelf registration statement, resulted in net proceeds of approximately $19.7 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale to partially repay borrowings made under its credit facility made in connection with its acquisition of the remaining 25% ownership interest in NOARK.

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

The preferred units are reflected on the Partnership s consolidated balance sheet as preferred equity within Partners Capital. In accordance with Securities and Exchange Commission Staff Accounting Bulletin No. 68, Increasing Rate Preferred Stock, the preferred units were recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. The imputed dividend cost is the result of the preferred units not having a dividend yield during the first year after their issuance on March 13, 2006. The total imputed dividend cost of $2.4 million on the preferred units, including the $0.5 million of imputed dividend cost related to the additional 10,000 units, was allotted to common limited partners and the general partner s interests within partner s capital on the consolidated balance sheet and is based upon the present value of the net proceeds received using the 6.5% stated yield commencing March 13, 2007. The imputed dividend cost is amortized for the period from the respective issuances of the preferred units through March 13, 2007, and the amortization is presented as a reduction of net income to determine net income attributable to common limited partners and the general partner. Amortization of the imputed dividend cost for the three and nine months ended September 30, 2006 was $0.6 million and $1.3 million, respectively. 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.

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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 to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the general partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and general partner distributions declared by the Partnership for the period from January 1, 2005 through September 30, 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	$1,501
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
May 15, 2006	March 31, 2006	$0.84	$10,541	$3,766
August 14, 2006	June 30, 2006	$0.85	$11,118	$4,059

On October 27, 2006, the Partnership declared a cash distribution of $0.85 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2006. The $15.2 million distribution, including $4.1 million to the General Partner, will be paid on November 14, 2006 to unitholders of record at the close of business on November 7, 2006.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2006	December 31, 2005	Estimated Useful Lives In Years
Pipelines, processing and compression facilities	$ 590,015	$ 443,729	15 40
Rights of way	29,906	19,252	20 40
Buildings	3,797	3,350	40
Furniture and equipment	3,306	1,525	3 7
Other	1,984	889	3 10
	629,008	468,745	
Less accumulated depreciation	(38,374)	(23,679)	
	$ 590,634	$ 445,066	

On May 2, 2006, the Partnership acquired the remaining 25% ownership interest in NOARK for $69.0 million in cash, including the repayment of the $39.0 million of NOARK notes at the date of acquisition (see Note 10). The Partnership acquired the initial 75% ownership interest in NOARK for approximately $179.8 million in October 2005 (see Note 8). During the third quarter of 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to customer contracts and customer relationships intangible assets and goodwill based upon the preliminary findings of an independent valuation firm (see Note 2) and allocated additional amounts to property, plant and equipment. Due to the recent date of both acquisitions, the purchase price allocation is subject to adjustment and could change significantly as the Partnership continues to evaluate this allocation. At December 31, 2005, the portion of the purchase price allocated to property, plant and equipment for NOARK was included within pipelines, processing and compression facilities.

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NOTE 7 OTHER ASSETS

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

	September 30, 2006	December 31, 2005
Deferred finance costs, net of accumulated amortization of $3,427 and $1,636 at September 30, 2006 and December 31, 2005, respectively	$ 13,049	$ 15,034
Security deposits	1,474	1,599
Other	125	68
	$ 14,648	$ 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 (RESTATED)

NOARK

On May 2, 2006, the Partnership acquired the remaining 25% equity ownership interest in NOARK from Southwestern, a wholly-owned subsidiary of Southwestern Energy Company (NYSE: SWN), for a net purchase price of $65.5 million, consisting of $69.0 million of cash to the seller (including the repayment of the $39.0 million of outstanding NOARK notes at the date of acquisition), less the seller s interest in NOARK s working capital (including cash on hand and net payables to the seller) at the date of acquisition of $3.5 million. In October 2005, the Partnership acquired from Enogex, Inc., a wholly-owned subsidiary of OGE Energy Corp. (NYSE: OGE), all of the outstanding equity of Atlas Arkansas Pipeline, LLC, which owned the initial 75% ownership interest in NOARK, for total consideration of $179.8 million, including $16.8 million for working capital adjustments and other related transaction costs. NOARK s assets included a Federal Energy Regulatory Commission (FERC)-regulated interstate pipeline and an unregulated natural gas gathering system. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141, Business Combinations (SFAS No. 141). The following table presents the preliminary purchase price allocation, as adjusted through September 30, 2006, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in both acquisitions, based on their fair values at the date of the respective acquisitions (in thousands):

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

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Due to the recent date of both acquisitions, the purchase price allocation for NOARK is based upon preliminary data that remains subject to adjustment and could further change significantly as the Partnership continues to evaluate this allocation. The Partnership s ownership interests in the results of NOARK s operations associated with each acquisition are included within its consolidated financial statements from the respective dates of the acquisitions.

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 May 2006, November 2005 and June 2005 (see Note 3), the May 2006 and December 2005 issuances of senior notes (see Note 10), and the May 2006 and March 2006 issuances of the 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 and financing transactions 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 September 30,		Nine Months Ended September 30,	
	2006 (Restated)	2005	2006 (Restated)	2005
Total revenue and other income	$ 120,546	$ 124,522	$ 347,857	$ 333,488
Net income	$ 7,001	$ 8,415	$ 26,383	$ 13,160
Net income attributable to common limited partners and the general partner	$ 6,374	$ 7,939	$ 24,842	$ 11,770
Net income attributable to common limited partners per unit:				
Basic	$ 0.20	$ 0.42	$ 1.04	$ 0.46
Diluted	$ 0.19	$ 0.42	$ 1.03	$ 0.45

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NOTE 9 DERIVATIVE INSTRUMENTS (RESTATED)

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 September 30, 2006 and December 31, 2005, the Partnership reflected net hedging liabilities on its consolidated balance sheets of $27.7 million and $30.4 million, respectively. Of the $29.5 million of net loss in accumulated other comprehensive loss at September 30, 2006, if the fair value of the instruments remain at current market values, the Partnership will reclassify $14.1 million of losses to its consolidated statements of income over the next twelve month period as these contracts expire, and $15.4 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 $4.9 million and $2.5 million for the three months ended September 30, 2006 and 2005, respectively, and losses of $10.5 million and $4.4 million for the nine months ended September 30, 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 $3.7 million and a loss of $0.8 million for the three months ended September 30, 2006 and 2005, respectively, and a gain of $4.6 million and a loss of $0.7 million for the nine months ended September 30, 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.

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As of September 30, 2006, the Partnership had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[1] (in thousands)
2006	17,262,000	$ 0.788	$ (1,908)
2007	84,924,000	0.849	(2,344)
2008	33,012,000	0.697	(5,659)
2009	8,568,000	0.746	(1,244)
			$ (11,155)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/Liability[3] (in thousands) (Restated)	Option Type
2008	720,000	40,219,000	$ 60.00	$ 2,994	Puts purchased
2008	720,000	40,219,000	84.00	(1,878)	Calls sold
2009	720,000	40,219,000	60.00	3,918	Puts purchased
2009	720,000	40,219,000	81.00	(2,634)	Calls sold
				$ 2,400	

Natural Gas Sales

Production Period Ended December 31,	Volumes (MMBTU)[2]	Average Fixed Price (per MMBTU)	Fair Value Asset/(Liability)[3] (in thousands)
2006	200,000	$ 7.019	$ 107
2007	1,080,000	7.255	(451)
2008	240,000	7.270	(223)
			$ (567)

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (MMBTU)[2]	Average Fixed Price (per MMBTU)	Fair Value Asset[3] (in thousands)
2006	300,000	$ (0.525)	$ 49
2007	1,080,000	(0.535)	369
2008	240,000	(0.555)	131
			$ 549

Natural Gas Purchases

Production Period Ended December 31,	Volumes (MMBTU)[2]	Average Fixed Price (per MMBTU)	Fair Value Liability[3] (in thousands)
2006	720,000	$ 8.384	$ (1,369)
2007	6,960,000	8.855(4)	(11,059)
2008	3,336,000	8.872(5)	(3,723)
2009	2,400,000	8.450	(1,682)
			$ (17,833)

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Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (MMBTU)(2)	Average Fixed Price (per MMBTU)	Fair Value Asset(3) (in thousands)
2006	1,080,000	$ (0.835)	$ 189
2007	6,960,000	(0.903)	272
2008	3,336,000	(1.042)	272
2009	2,400,000	(0.600)	130
			$ 863

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability(3) (in thousands)
2006	17,800	$ 53.358	$ (179)
2007	77,900	56.175	(900)
2008	65,400	59.424	(621)
2009	33,000	62.700	(159)
			$ (1,859)

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/Liability(3) (in thousands)	Option Type
			(Restated)	
2006	3,300	$ 60.000	$ 2	Puts purchased
2006	3,300	73.380	(1)	Calls sold
2007	13,200	60.000	28	Puts purchased
2007	13,200	73.380	(45)	Calls sold
2008	17,400	60.000	64	Puts purchased
2008	17,400	72.807	(101)	Calls sold
2009	30,000	60.000	125	Puts purchased
2009	30,000	71.250	(210)	Calls sold
			$ (138)	

Total net liability	$	(27,740)

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

(2) MMBTU represents million British Thermal Units.

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

(4) Includes the Partnership s premium received from its sale of an option for it to sell 4,800,000 mmbtu of natural gas at an average price of $15.25 per mmbtu for the year ended December 31, 2007, partially offset by its premium paid from its purchase of an option to purchase 1,200,000 mmbtu of natural gas at $26.00 per mmbtu.

(5) Includes the Partnership s premium received from its sale of an option for it to sell 936,000 mmbtu of natural gas for the year ended December 31, 2008 at $15.50 per mmbtu.

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NOTE 10 DEBT (RESTATED)

Total debt consists of the following (in thousands):

	September 30, 2006	December 31, 2005
Revolving Credit Facility	$ 13,500	$ 9,500
Senior Notes	286,005	250,000
NOARK Notes		39,000
Other debt	135	125
	299,640	298,625
Less current maturities	(92)	(1,263)
	$ 299,548	$ 297,362

*Credit Facility **(Restated)***

The Partnership has a $225.0 million credit facility with a syndicate of banks which matures in June 2011. The credit facility bears interest, at the Partnership s option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding credit facility borrowings at September 30, 2006 was 7.1%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $10.1 million was outstanding at September 30, 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 subsidiaries, and by the guaranty of each of its subsidiaries. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is in compliance with these covenants as of September 30, 2006.

The events which constitute an event of default for the Partnership s credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s general partner.

The credit facility requires the Partnership to maintain a ratio of senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.25 to 1.0; and an interest coverage ratio (as defined in the credit facility) of not less than 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of September 30, 2006, the Partnership s ratio of senior secured debt to EBITDA was 0.3 to 1.0, its funded debt ratio was 3.6 to 1.0 and its interest coverage ratio was 3.7 to 1.0.

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

Senior Notes

In December 2005, the Partnership and its subsidiary, Atlas Pipeline Finance Corp. (APFC), issued $250.0 million of 10-year, 8.125% senior unsecured notes (Senior Notes) in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $243.1 million, after underwriting commissions and other transaction costs. In May 2006, the Partnership and APFC issued an additional $35.0 million of senior unsecured notes at 103% par value, with a resulting effective yield of approximately 7.6%, for net proceeds of approximately $36.6 million, including accrued interest and net of initial purchaser s discount and other transaction costs. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time on or after December 15, 2010 at certain redemption prices, together with accrued unpaid interest to the date of redemption. In addition, prior to December 15, 2008, the Partnership may redeem up to 35% of the aggregate principal amount of the Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes are also subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales 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 September 30, 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 did not meet the aforementioned deadlines, the Senior Notes would be subject to additional interest, up to 1% per annum, until such time that the deadlines had been met. On April 19, 2006, the Partnership filed an exchange offer registration statement for the Senior Notes with the Securities and Exchange Commission, which was declared effective on July 11, 2006. The exchange offer was consummated on August 17, 2006, thereby fulfilling all of the requirements of the Senior Notes registration rights agreement by the specified dates.

NOARK Notes

On May 2, 2006, the Partnership acquired the remaining 25% equity ownership interest in NOARK from Southwestern. Prior to this acquisition, NOARK s subsidiary, NOARK Pipeline Finance, L.L.C., had $39.0 million in principal amount outstanding of 7.15% notes due in 2018. The notes were presented as debt on the Partnership s consolidated balance sheet, however, the obligation for their repayment had contractually been 100% severally allocated to Southwestern. In connection with the acquisition of the remaining 25% equity ownership interest in NOARK, Southwestern acquired NOARK Pipeline Finance, L.L.C. and retained the obligation for the notes, with the result that neither the Partnership nor NOARK have any further liability with respect to them.

NOTE 11 COMMITMENTS AND CONTINGENCIES

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

As of September 30, 2006, the Partnership is committed to expend approximately $23.2 million on pipeline extensions, compressor station upgrades and processing facility upgrades, including $2.1 million related to the Sweetwater gas plant, the Partnership s new gas processing plant which commenced operations in Beckham County, Oklahoma in September 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 September 30, 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 September 30, 2006, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined in the LTIP. Of the units outstanding under the LTIP at September 30, 2006, 39,630 units will vest within the following twelve months. All units outstanding under the LTIP at September 30, 2006 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs were $0.1 million for both the three months ended September 30, 2006 and 2005, respectively, and $0.3 million for both the nine months ended September 30, 2006 and 2005, respectively. These amounts 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 unit-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 September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Outstanding, beginning of period	111,219	110,378	110,128	58,329
Granted[1]	33,000		34,091	67,399
Matured	(31,152)	(250)	(31,152)	(14,581)
Forfeited				(1,019)
Outstanding, end of period	113,067	110,128	113,067	110,128
Non-cash compensation expense recognized (in thousands)	$ 450	$ 651	$ 1,294	$ 1,735

(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 $43.05 for awards granted for the three months ended September 30, 2006. There were no awards granted during the three months ended September 30, 2005. The weighted average price for awards granted for

the nine months ended September 30, 2006 and 2005 was $42.99 and $48.59, respectively.

At September 30, 2006, the Partnership had approximately $2.7 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIP based upon the fair value of the awards.

Incentive Compensation Agreements

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

The Partnership recognized compensation expense of $1.2 million and $0.1 million for the three months ended September 30, 2006 and 2005, respectively, and $2.8 million and $1.1 million for the nine months ended September 30, 2006 and 2005, respectively, related to the vesting of awards under these incentive compensation agreements. Based upon management s estimate of the probable outcome of the performance targets at September 30, 2006, 226,169 common unit awards are ultimately expected to be issued under these agreements. At September 30, 2006, the Partnership had approximately $4.0 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 it on the Partnership s behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $0.4 million for both the three months ended September 30, 2006 and 2005, and $2.0 million and $1.4 million for the nine months ended

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September 30, 2006 and 2005, respectively, for compensation and benefits related to their executive officers. For the three months ended September 30, 2006 and 2005, direct reimbursements were $8.0 million and $5.2 million, respectively, and $21.2 million and $17.1 million for the nine months ended September 30, 2006 and 2005, 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 (RESTATED)

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

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

	Three Months Ended September 30, 2006 (Restated)	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006 (Restated)	Nine Months Ended September 30, 2005
Mid-Continent				
Revenue:				
Natural gas and liquids	$ 103,671	$ 96,234	$ 300,694	$ 218,268
Transportation and compression	6,707		20,817	
Interest income and other	3,080	60	3,098	77
Total revenue and other income	113,458	96,294	324,609	218,345
Costs and expenses:				
Natural gas and liquids	89,679	82,537	252,577	184,578
Plant operating	3,853	2,745	11,006	7,242
Transportation and compression	1,623		4,794	
General and administrative	3,356	1,258	8,988	4,307
Minority interest in NOARK			118	
Depreciation and amortization	5,200	2,739	14,034	6,597
Total costs and expenses	103,711	89,279	291,517	202,724
Segment profit	$ 9,747	$ 7,015	$ 33,092	$ 15,621
Appalachia				
Revenue:				
Transportation and compression affiliates	$ 6,951	$ 6,248	$ 22,659	$ 16,447
Transportation and compression third parties	19	16	65	54
Interest income and other	118	87	524	275
Total revenues and other income	7,088	6,351	23,248	16,776
Costs and expenses:				
Transportation and compression	1,325	871	3,610	2,169
General and administrative	929	801	2,848	2,410
Depreciation and amortization	952	699	2,651	1,898
Total costs and expenses	3,206	2,371	9,109	6,477
Segment profit	$ 3,882	3,980	$ 14,139	$ 10,299
Reconciliation of segment profit to net income:				
Segment profit				
Mid-Continent	$ 9,747	$ 7,015	$ 33,092	$ 15,621
Appalachia	3,882	3,980	14,139	10,299
Total segment profit	13,629	10,995	47,231	25,920
Corporate general and administrative expenses	(928)	(784)	(2,847)	(2,411)
Interest expense	(5,700)	(3,166)	(18,191)	(8,478)
Other		9		(138)

Net income	$ 7,001	$ 7,054	$ 26,193	$ 14,893
<u>Capital Expenditures</u>:				
Mid-Continent	$ 20,706	$ 7,360	$ 47,903	$ 21,890
Appalachia	5,225	4,276	13,840	12,629
	$ 25,931	$ 11,636	$ 61,743	$ 34,519

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	September 30, 2006 (Restated)	December 31, 2005
Balance sheet		
Total assets:		
Mid-Continent	$ 716,967	$ 668,782
Appalachia	34,246	43,428
Corporate other	20,607	30,516
	$ 771,820	$ 742,726
Goodwill:		
Mid-Continent	$ 61,136	$ 109,141
Appalachia	2,305	2,305
	$ 63,441	$ 111,446

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006 (Restated)	2005	2006 (Restated)	2005
Natural gas and liquids:				
Natural gas	$ 53,393	$ 54,970	$ 152,990	$ 122,837
NGLs	45,605	37,827	128,523	86,761
Condensate	1,427	1,547	4,950	3,768
Other (1)	3,246	1,890	14,231	4,902
Total	$ 103,671	$ 96,234	$ 300,694	$ 218,268
Transportation and compression:				
Affiliates	$ 6,951	$ 6,248	$ 22,659	$ 16,447
Third parties	6,726	16	20,882	54
Total	$ 13,677	$ 6,264	$ 43,541	$ 16,501

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

NOTE 15 RESTATEMENT

Subsequent to the issuance of the Partnership s consolidated financial statements for the three and nine months ended September 30, 2006, management of the Partnership determined that it had not properly recognized additional net income of $2.3 million within its consolidated financial statements for both the three and nine months ended September 30, 2006. The additional net income was the result of the recognition of an unrealized gain with respect to certain financial derivative instruments under SFAS No. 133. Specifically, the Partnership entered into a significant number of option instruments (a combination of puts purchased and calls sold that are commonly known as costless collars) in September 2006 to hedge its exposure to movements in commodity prices that were not appropriately valued within its consolidated financial statements under the provisions of SFAS No. 133. While the costless collars were valued appropriately with regard to their intrinsic value, the Partnership did not record a fair value for the time-value component of the derivative instruments. All of the Partnership s other derivative instruments that were in effect during 2006 have been appropriately recorded within its consolidated financial statements. The following tables detail the effects of the restatement (in thousands, except per share amounts):

	September 30, 2006		
CONSOLIDATED BALANCE SHEET	**As Previously Reported**	**Adjustment**	**As Restated**
Long-term hedge asset	$ 2,575	$ 2,400	$ 4,975
Total assets	769,420	2,400	771,820
Current portion of hedge liability	17,421	10	17,431
Total current liabilities	75,947	10	75,957
Long-term hedge liability	18,782	128	18,910
Common limited partner s interests	354,758	2,217	356,975
General partner s interest	11,107	45	11,152
Total partners capital	375,143	2,262	377,405
Total liabilities and partners capital	769,420	2,400	771,820

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CONSOLIDATED STATEMENT OF INCOME	Three months ended September 30, 2006 As Previously Reported	Adjustment	As Restated
Natural gas and liquids revenue	$ 101,409	$ 2,262	$ 103,671
Total revenue and other income	118,284	2,262	120,546
Net income	4,739	2,262	7,001
Net income common limited partners interest	350	2,217	2,567
Net income general partner s interest	3,762	45	3,807
Net income attributable to common limited partners and the general partner	4,112	2,262	6,374
Basic net income per common limited partners unit	0.03	0.17	0.20
Diluted net income per common limited partners unit	0.03	0.16	0.19

CONSOLIDATED STATEMENT OF INCOME	Nine months ended September 30, 2006 As Previously Reported	Adjustment	As Restated
Natural gas and liquids revenue	$ 298,432	$ 2,262	$ 300,694
Total revenue and other income	345,595	2,262	347,857
Net income	23,931	2,262	26,193
Net income common limited partners interest	11,447	2,217	13,664
Net income general partner s interest	11,222	45	11,267
Net income attributable to common limited partners and the general partner	22,669	2,262	24,931
Basic net income per common limited partners unit	0.89	0.18	1.07
Diluted net income per common limited partners unit	0.88	0.17	1.05

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL	Nine months ended September 30, 2006 As Previously Reported	Adjustment	As Restated
Net income common limited partners	$ 11,447	$ 2,217	$ 13,664
Net income general partner	11,222	45	11,267
Balance at September 30, 2006 common limited partners	354,758	2,217	356,975
Balance at September 30, 2006 general partner	11,107	45	11,152

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CONSOLIDATED STATEMENT OF CASH FLOWS	Nine months ended September 30, 2006 As Previously Reported	Adjustment	As Restated
Net income	$ 23,931	$ 2,262	$ 26,193
Non-cash loss (gain) on derivative value	155	(2,262)	(2,107)
Net cash provided by operating activities	39,915		39,915
Net change in cash and cash equivalents	(26,251)		(26,251)

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

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.

Restatement

Subsequent to the issuance of the our consolidated financial statements for the three and nine months ended September 30, 2006, our management determined that we had not properly recognized additional net income of $2.3 million within our consolidated financial statements for both the three and nine months ended September 30, 2006. The additional net income was the result of the recognition of a gain with respect to certain financial hedge instruments under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities. This Management s Discussion and Analysis of Financial Condition and Results of Operations gives effect to this restatement. For additional information regarding the restatement, refer to Note 15 to the consolidated financial statements in Item 1. Financial Statements.

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 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 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;

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

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

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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 September 30, 2006, we have completed six acquisitions at an aggregate cost of approximately $590.1 million, including, most recently:

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

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 130 MMcf/d and a gas treatment facility in Prentiss, Oklahoma, with a total capacity of approximately 200 MMcf/d.

Sweetwater Processing Facility and Gathering System

On September 27, 2006, we announced the initiation of operations of our new gas processing plant and gathering system (Sweetwater plant) in Beckham County, Oklahoma. The Sweetwater plant, with a processing capacity of 120 MMcf/d, is located west of our Elk City gas plant, and was built to further access natural gas production actively being developed in western Oklahoma and the Texas panhandle.

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.

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

We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. A 10% change in the average price of NGLs, natural gas and condensate we process and sell would result in a change to our consolidated income for the twelve-month period ending September 30, 2007 of approximately $5.2 million.

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Operating data:				
Appalachia:				
Average throughput volumes (Mcf/d)	63,909	57,294	61,473	54,804
Average transportation rate per mcf	$ 1.19	$ 1.19	$ 1.35	$ 1.10
Mid-Continent:				
Velma system:				
Gathered gas volume (Mcf/d)	62,113	68,469	61,641	69,091
Processed gas volume (Mcf/d)	58,296	62,439	58,881	64,581
Residue gas volume (Mcf/d)	45,724	53,235	46,042	52,471
NGL production (Bbl/d)	6,598	6,877	6,536	6,812
Condensate volume (Bbl/d)	205	293	209	269
Elk City system:				
Gathered gas volume (Mcf/d)	284,461	240,774	270,957	242,294
Processed gas volume (Mcf/d)	136,101	115,913	134,169	116,688
Residue gas volume (Mcf/d)	123,275	106,783	121,661	107,182
NGL production (Bbl/d)	6,049	5,130	6,016	5,317
Condensate volume (Bbl/d)	59	123	125	121
NOARK system:				
Average throughput volume (Mcf/d)	226,962		236,331	

Three Months Ended September 30, 2006 Compared to Three Months Ended September 30, 2005

Revenue. Natural gas and liquids revenue was $103.7 million for the three months ended September 30, 2006, an increase of $7.5 million from $96.2 million for the three months ended September 30, 2005. The increase was attributable to revenue contribution from the NOARK system, of which a 75% ownership interest was acquired in October 2005 and the remaining 25% ownership interest was acquired in May 2006, of $9.9 million and an increase of $5.0 million from the Elk City system due primarily to an increase in

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volumes, partially offset by a decrease from the Velma system of $7.4 million due mainly to a decrease in natural gas prices and lower volumes resulting mainly from the expiration of a short-term low-margin gathering and processing agreement, the curtailment of our throughput on certain connected third-party pipelines due to maintenance and pressure issues, and reduced throughput due to a temporary outage at one of our compressor stations resulting from fire damage. Gross natural gas gathered on the Elk City system averaged 284.5 MMcf/d for the three months ended September 30, 2006, an 18.1% increase from the prior year comparable quarter. Gross natural gas gathered averaged 62.1 MMcf/d on the Velma system for the three months ended September 30, 2006, a decrease of 9.3% from the comparable prior year quarter. The decrease in throughput on the Velma system was mainly the result of the items mentioned previously.

Transportation and compression revenue increased to $13.7 million for the three months ended September 30, 2006 from $6.3 million for the comparable prior year quarter. This $7.4 million increase was primarily due to contributions from the transportation revenues associated with the NOARK system of $5.2 million, a $1.5 million increase from the Elk City system and a $0.7 million increase from the Appalachia system due to higher volumes. For the NOARK system, average throughput volume was 227.0 MMcf/d for the three months ended September 30, 2006. Appalachia s average throughput volume was 63.9 MMcf/d for the three months ended September 30, 2006 as compared with 57.3 MMcf/d for the three months ended September 30, 2005, an increase of 6.6 MMcf/d or 11.5%. Our Appalachia system average transportation rate was $1.19 per Mcf for both the three months ended September 30, 2006 and 2005. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system.

Interest income and other was $3.2 million for the three months ended September 30, 2006, an increase of $3.1 million from the prior year comparable quarter. This increase was mainly due to a $2.7 million gain from the sale of certain gathering pipelines within the Velma system for cash proceeds of $7.5 million.

Costs and Expenses. Natural gas and liquids cost of goods sold of $89.7 million and plant operating expenses of $3.9 million for the three months ended September 30, 2006 represented increases of $7.1 million and $1.1 million, respectively, from the comparable prior year quarter amounts due primarily to contribution from the NOARK acquisition, higher Elk City system amounts due mainly to higher volume and $2.8 million of revisions to previously estimated second quarter production volumes, partially offset by lower Velma system natural gas and liquids cost of goods sold due principally to lower natural gas prices and lower volume resulting from the expiration of a short-term low-margin gathering and processing agreement, the curtailment of our throughput on certain connected third-party pipelines due to maintenance and pressure issues, and reduced throughput due to a temporary outage at one of our compressor stations resulting from fire damage. Transportation and compression expenses increased $2.1 million to $2.9 million for the three months ended September 30, 2006 due mainly to NOARK system operating costs and higher Appalachia system operating costs as a result of higher maintenance expense as a result of additional wells connected to our gathering system.

General and administrative expenses, including amounts reimbursed to affiliates, increased $2.4 million to $5.2 million for the three months ended September 30, 2006 compared with $2.8 million for the prior year comparable quarter. This increase was mainly due to an 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 of the NOARK acquisition and capital raising opportunities.

Depreciation and amortization increased to $6.2 million for the three months ended September 30, 2006 compared with $3.4 million for the three months ended September 30, 2005 due primarily to the depreciation associated with the NOARK assets acquired during 2005 and 2006.

Interest expense increased to $5.7 million for the three months ended September 30, 2006 as compared with $3.2 million for the comparable prior year quarter. This $2.5 million increase was primarily

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due to interest associated with our May 2006 and December 2005 issuances of 10-year senior unsecured notes, partially offset by a decrease in interest associated with borrowings under the credit facility and $1.0 million of interest cost capitalized principally attributable to the construction of the Sweetwater processing plant and gathering system.

Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Revenue. Natural gas and liquids revenue was $300.7 million for the nine months ended September 30, 2006, an increase of $82.4 million from $218.3 million for the nine months ended September 30, 2005. The increase was primarily attributable to revenue contributions from the NOARK system, of which a 75% ownership interest was acquired in October 2005 and the remaining 25% ownership interest was acquired in May 2006, of $37.0 million and the Elk City system, which was acquired in April 2005, of $54.0 million, partially offset by a decrease from the Velma system of $8.6 million due principally to a decrease in natural gas prices and lower volumes resulting from the expiration of a short-term low-margin gathering and processing agreement. Gross natural gas gathered on the Elk City system averaged 271.0 MMcf/d for the nine months ended September 30, 2006, an 11.8% increase from the prior year period. Gross natural gas gathered averaged 61.6 MMcf/d on the Velma system for the nine months ended September 30, 2006, a decrease of 10.8% from the comparable prior year nine month period due the expiration of a short-term low-margin gathering and processing agreement.

Transportation and compression revenue increased to $43.5 million for the nine months ended September 30, 2006 from $16.5 million for the comparable prior year period. This $27.0 million increase was primarily due to contributions from the transportation revenues associated with the NOARK system of $17.0 million and the Elk City system of $3.8 million and increases in the Appalachia system average transportation rate earned and volume of natural gas transported. For the NOARK system, average throughput volume was 236.3 MMcf/d for the nine months ended September 30, 2006. The Appalachia system s average throughput volume was 61.5 MMcf/d for the nine months ended September 30, 2006 as compared with 54.8 MMcf/d for the nine months ended September 30, 2005, an increase of 6.7 MMcf/d or 12.2%. The Appalachia system average transportation rate was $1.35 per Mcf for the nine months ended September 30, 2006 as compared with $1.10 per Mcf for the prior year nine month period, an increase of $0.25 per Mcf. The increase in the Appalachia system 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.

Interest income and other was $3.6 million for the nine months ended September 30, 2006, an increase of $3.3 million from the prior year comparable period. This increase was mainly due to a $2.7 million gain from the sale of certain gathering pipelines within the Velma system for cash proceeds of $7.5 million.

Costs and Expenses. Natural gas and liquids cost of goods sold of $252.6 million and plant operating expenses of $11.0 million for the nine months ended September 30, 2006 represented increases of $68.0 million and $3.8 million, respectively, from the comparable prior year amounts due primarily to contributions from the acquisitions of NOARK and Elk City, with the increase in natural gas and liquids cost of goods sold partially offset by a decrease from the Velma system due to a decline in natural gas prices and lower volume resulting from the expiration of a short-term low-margin gathering and processing agreement. Transportation and compression expenses increased $6.2 million to $8.4 million for the nine months ended September 30, 2006 due mainly to NOARK system operating costs and higher Appalachia system 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 $5.6 million to $14.7 million for the nine months ended September 30, 2006 as compared with the prior year comparable nine month period. This increase was mainly due to an increase in non-cash compensation

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expense related to vesting of phantom and common unit awards and higher costs associated with managing our business, including management of our NOARK and Elk City acquisitions and capital raising opportunities.

Depreciation and amortization increased to $16.7 million for the nine months ended September 30, 2006 compared with $8.5 million for the nine months ended September 30, 2005 due primarily to the depreciation and amortization associated with the NOARK and Elk City assets acquired during 2005 and 2006.

Interest expense increased to $18.2 million for the nine months ended September 30, 2006 as compared with $8.5 million for the comparable prior year nine month period. This $9.7 million increase was primarily due to interest associated with our May 2006 and December 2005 issuances of 10-year senior unsecured notes, partially offset by a decrease in interest associated with borrowings under the credit facility and $1.9 million of interest cost capitalized principally attributable to the construction of the Sweetwater processing plant and gathering system.

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

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through the retention of cash and additional borrowings; and
- debt principal payments through additional borrowings as they become due or by the issuance of additional limited partner units.

At September 30, 2006, we had $13.5 million of outstanding borrowings under our credit facility and $10.1 million of outstanding letters of credit which are not reflected as borrowings on our consolidated balance sheet, with $211.5 million of remaining committed capacity under the $225.0 million credit facility, subject to covenant limitations (see Credit Facility). In addition to the availability under the credit facility, we have a universal shelf registration statement on file with the Securities and Exchange Commission, which allows us to issue equity or debt securities (see Shelf Registration Statement), of which $352.1 million remains available at September 30, 2006. At September 30, 2006, we had a working capital deficit of $4.0 million compared with a working capital position of $16.8 million at December 31, 2005. This decrease was primarily due to the utilization of cash on hand between periods, principally raised through financing transactions during 2005, to fund expansion capital expenditures incurred during the nine months ended September 30, 2006, including the construction of the Sweetwater processing plant and gathering system. 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 cash flow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings and the issuance of additional limited partner units.

Cash Flows Nine Months Ended September 30, 2006 Compared to Nine Months Ended September 30, 2005

Net cash provided by operating activities of $39.9 million for the nine months ended September 30, 2006 represented an increase of $12.8 million from $27.1 million for the comparable prior year nine month

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period. The increase is derived principally from increases in net income of $11.3 million, depreciation and amortization of $8.2 million, and non-cash compensation expense of $1.3 million, partially offset by a $4.5 million decrease in cash flows from operating activities resulting from changes in the components of working capital and a $2.6 million increase in gains recognized on sales of assets for which the cash received was recorded within cash flows from investing activities. The increases in net income and depreciation and amortization were principally due to the contributions from the NOARK and Elk City acquisitions.

Net cash used in investing activities was $84.1 million for the nine months ended September 30, 2006, a decrease of $145.8 million from $229.9 million for the comparable prior year nine month period. This decrease was principally due to a $165.2 million decrease in net cash paid for acquisitions and a $7.6 million increase in cash proceeds from the sale of assets, partially offset by a $27.2 million increase in capital expenditures. Net cash paid for acquisitions in 2006 consisted of the acquisition of the remaining 25% equity ownership interest in NOARK, while net cash paid for acquisitions in 2005 consisted of the acquisition of Elk City. The $7.6 million increase in cash proceeds received from the sale of assets consists principally of the sale of certain gathering pipelines within the Velma system. See further discussion of capital expenditures under Capital Requirements.

Net cash provided by financing activities was $18.0 million for the nine months ended September 30, 2006, a decrease of $178.6 million from $196.6 million of net cash used in financing activities for the comparable prior year nine month period. This decrease was principally due to a $125.3 million increase in net repayments under our credit facility, a $72.0 million decrease in net proceeds received from the issuance of common units, a $38.9 million increase in repayment of debt, and a $20.7 million increase in cash distributions to common limited partners and the general partner. These amounts were partially offset by a $39.9 million increase in net proceeds from the issuance of cumulative convertible preferred units and a $36.6 million increase in net proceeds from the issuance of senior notes. The changes in net proceeds from the issuance of common units, preferred units, and senior notes and borrowing activity under our credit facility principally relate to the construction of the Sweetwater gas plant, a new natural gas processing plant in Oklahoma which initiated operations at the end of the third quarter of 2006, and financing the acquisitions of Elk City in April 2005, the 75% ownership interest in NOARK in October 2005, and the remaining 25% ownership interest in NOARK in May 2006. The increase in cash distributions to common limited partners and the general partner are 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 September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Maintenance capital expenditures	$ 843	$ 245	$ 2,921	$ 1,110
Expansion capital expenditures	25,088	11,391	58,822	33,409
Total	$ 25,931	$ 11,636	$ 61,743	$ 34,519

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Expansion capital expenditures increased to $25.1 million and $58.8 million for the three and nine months ended September 30, 2006, respectively, due principally to expansions of the Appalachia, Velma and Elk City gathering systems, and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. Expansion capital expenditures for our Mid-Continent region for the three and nine months ended September 30, 2006 also included costs incurred of approximately $8.6 million and $24.1 million, respectively, related to the construction of the Sweetwater gas plant, a new natural gas processing plant in Oklahoma which initiated operations at the end of the third quarter of 2006. As of September 30, 2006, we have incurred $34.8 million of the projected $40 million in expenditures related to the Sweetwater project, with the remaining costs expected to be incurred as its gathering pipeline system is expanded during the remainder of 2006 and in 2007. Maintenance capital expenditures for the three and nine months ended September 30, 2006 increased to $0.8 million and $2.9 million, respectively, due to the additional maintenance requirements of the NOARK and Elk City acquisitions. As of September 30, 2006, we are committed to expend approximately $23.2 million on pipeline extensions, compressor station upgrades and processing facility upgrades, including $2.1 million related to the Sweetwater gas plant.

Partnership Distributions

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

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

Available cash is initially distributed 98% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The general partner s incentive distributions declared for three and nine months ended September 30, 2006 was $3.8 million and $11.0 million, respectively.

Common Equity Offerings

On May 12, 2006, we sold 500,000 common units to Wachovia Securities, which then offered the common unit to public investors. The units, which were issued under our previously filed shelf registration statement, resulted in net proceeds of approximately $19.7 million, after underwriting commissions and other transaction costs. We utilized the net proceeds from the sale to partially repay borrowings under our credit facility made in connection with our acquisition of the remaining 25% ownership interest in NOARK.

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 September 30, 2006, $352.1 million remains available for issuance under the shelf registration statement. However, the amount, type and timing of any offerings will depend upon, among other things, our funding requirements, prevailing market conditions, and compliance with our credit facility covenants.

Private Placement of Convertible Preferred Units

On March 13, 2006, we 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 gross proceeds of $30.0 million. We also sold an additional 10,000 6.5% cumulative preferred units to Sunlight Capital Partners for $10.0 million on May 19, 2006, pursuant to our right to require Sunlight Capital Partners to purchase such additional units under the purchase agreement with Sunlight. The preferred units are entitled to receive dividends of 6.5% per annum commencing on March 13, 2007, which will accrue and be paid quarterly on the same date as the distribution payment date for our common units. The preferred units are convertible, at the holder s option, into common units commencing on the date immediately following the first record date after March 13, 2007 at a conversion price equal to the lesser of $41.00 or 95% of the market price of our common units as of the date of the notice of conversion. We may elect to pay cash rather than issue common units in satisfaction of a conversion request. We have the right to call the preferred units at a specified premium. We have also filed a registration statement to cover the resale of the common units underlying the preferred units. The net proceeds from the initial issuance of the preferred units was used to fund a portion of our capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under our credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK. The preferred units are reflected on our consolidated balance sheet as preferred equity within Partners Capital. If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within Partners Capital on our consolidated balance sheet. Dividends accrued and paid on the preferred units and 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 June 2011. The credit facility bears interest, at our option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding credit facility borrowings at September 30, 2006 was 7.1%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $10.1 million was outstanding at September 30, 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

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guaranty of each of our wholly-owned subsidiaries. The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are in compliance with these covenants as of September 30, 2006.

The events which constitute an event of default are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against us in excess of a specified amount, and a change of control of our general partner.

The credit facility requires us to maintain a ratio of senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.25 to 1.0; and an interest coverage ratio (as defined in the credit facility) of not less than 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of September 30, 2006, our ratio of senior secured debt to EBITDA was 0.3 to 1.0, our funded debt ratio was 3.6 to 1.0 and our interest coverage ratio was 3.7 to 1.0.

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

Senior Notes

In December 2005, we and our subsidiary, Atlas Pipeline Finance Corp. (APFC), issued $250.0 million of 10-year, 8.125% senior unsecured notes (Senior Notes) in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $243.1 million, after underwriting commissions and other transaction costs. In May 2006, we and APFC issued an additional $35.0 million of senior unsecured notes at 103% par value, with a resulting effective yield of approximately 7.6%, for net proceeds of approximately $36.6 million, including accrued interest and net of initial purchaser s discount and other transaction costs. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time on or after December 15, 2010 at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Senior Notes are also redeemable at any time prior to December 15, 2010 at stated redemption prices, together with accrued and unpaid interest to the date of redemption. In addition, prior to December 15, 2008, we may redeem up to 35% of the aggregate principal amount of the Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes are also subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under the credit facility.

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 September 30, 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 did not meet the aforementioned deadlines, the Senior Notes would be subject to additional interest, up to 1% per annum, until such time that the deadlines had been met. On April 19, 2006,

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we filed an exchange offer registration statement for the Senior Notes with the Securities and Exchange Commission, which was declared effective on July 11, 2006. The exchange offer was consummated on August 17, 2006, thereby fulfilling all of the requirements of the Senior Notes registration rights agreement by the specified dates.

NOARK Notes

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

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenues and expenses during the reporting period. Although we believe our estimates are reasonable, actual results could differ from those estimates. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within our Annual Report on Form 10-K for the year ended December 31, 2005, and there have been no material changes to these policies through September 30, 2006.

New Accounting Standard

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). SAB 108 provides guidance on quantifying and evaluating the materiality of unrecorded misstatements. The SEC staff recommends that misstatements should be quantified using both a balance sheet and income statement approach and a determination be made as to whether either approach results in quantifying a misstatement which the registrant, after evaluating all relevant factors, considers material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct misstatements occurring in prior years that previously had been considered immaterial based on the appropriate use of the registrant s methodology. SAB 108 is effective for fiscal years ending on or after November 15, 2006. We do not currently expect SAB 108 to have a material impact on our consolidated financial position or results of operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (RESTATED)

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.

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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 June 30, 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 September 30, 2006, we had a $225.0 million revolving credit facility ($13.5 million outstanding) to fund the expansion of our existing gathering systems, acquire other natural gas gathering systems and fund working capital movements as needed. The weighted average interest rate for these borrowings was 7.1% at September 30, 2006. Holding all other variables constant, a 1% change in interest rates would change interest expense by $0.1 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of commodities rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. 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 September 30, 2007 of approximately $5.2 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 hedges, we recognize 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 September 30, 2006 and December 31, 2005, we reflected net hedging liabilities on our consolidated balance sheets of $27.7 million and $30.4 million, respectively. Of the $29.5 million of net loss in accumulated other comprehensive loss at September 30, 2006, if the fair value of the instruments remain at current market values, we will reclassify $14.1 million of losses to our consolidated statements of income over the next twelve month period as these contracts expire, and $15.4 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 $4.9 million and $2.5 million for the three months ended September 30, 2006 and 2005, respectively, and losses of $10.5 million and $4.4 million for the nine months ended September 30, 2006 and 2005, respectively, within our consolidated statements of income related to the settlement of qualifying hedge instruments. We also recognized a gain of $3.7 million and a loss of $0.8 million for the three months ended September 30, 2006 and 2005, respectively, and a gain of $4.6 million and a loss of $0.7 million for the nine months ended September 30, 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 September 30, 2006, we had the following NGLs, natural gas, and crude oil volumes hedged:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[(1)] (in thousands)
2006	17,262,000	$ 0.788	$ (1,908)
2007	84,924,000	0.849	(2,344)
2008	33,012,000	0.697	(5,659)
2009	8,568,000	0.746	(1,244)
			$ (11,155)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/Liability[(3)] (in thousands) (Restated)	Option Type
2008	720,000	40,219,000	$ 60.00	$ 2,994	Puts purchased
2008	720,000	40,219,000	84.00	(1,878)	Calls sold
2009	720,000	40,219,000	60.00	3,918	Puts purchased
2009	720,000	40,219,000	81.00	(2,634)	Calls sold
				$ 2,400	

Natural Gas Sales

Production Period Ended December 31,	Volumes (MMBTU)[(2)]	Average Fixed Price (per MMBTU)	Fair Value Asset/Liability[(3)] (in thousands)
2006	200,000	$ 7.019	$ 107
2007	1,080,000	7.255	(451)
2008	240,000	7.270	(223)
			$ (567)

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (MMBTU)[(2)]	Average Fixed Price (per MMBTU)	Fair Value Asset[(3)] (in thousands)
2006	300,000	$ (0.525)	$ 49
2007	1,080,000	(0.535)	369
2008	240,000	(0.555)	131
			$ 549

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Natural Gas Purchases

Production Period Ended December 31,	Volumes (MMBTU)[2]	Average Fixed Price (per MMBTU)	Fair Value Liability[3] (in thousands)
2006	720,000	$ 8.384	$ (1,369)
2007	6,960,000	8.855(4)	(11,059)
2008	3,336,000	8.872(5)	(3,723)
2009	2,400,000	8.450	(1,682)
			$ (17,833)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (MMBTU)[2]	Average Fixed Price (per MMBTU)	Fair Value Asset[3] (in thousands)
2006	1,080,000	$ (0.835)	$ 189
2007	6,960,000	(0.903)	272
2008	3,336,000	(1.042)	272
2009	2,400,000	(0.600)	130
			$ 863

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability[3] (in thousands)
2006	17,800	$ 53.358	$ (179)
2007	77,900	56.175	(900)
2008	65,400	59.424	(621)
2009	33,000	62.700	(159)
			$ (1,859)

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Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/Liability[3] (in thousands) (Restated)	Option Type
2006	3,300	$ 60.000	$ 2	Puts purchased
2006	3,300	73.380	(1)	Calls sold
2007	13,200	60.000	28	Puts purchased
2007	13,200	73.380	(45)	Calls sold
2008	17,400	60.000	64	Puts purchased
2008	17,400	72.807	(101)	Calls sold
2009	30,000	60.000	125	Puts purchased
2009	30,000	71.250	(210)	Calls sold
			$ (138)	
		Total net liability	$ (27,740)	

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

(2) MMBTU represents million British Thermal Units.

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

(4) Includes our premium received from the sale of an option for us to sell 4,800,000 mmbtu of natural gas at an average price of $15.25 per mmbtu for the year ended December 31, 2007, partially offset by our premium paid from our purchase of an option to purchase 1,200,000 mmbtu of natural gas at $26.00 per mmbtu.

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

ITEM 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our General Partner s Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were not effective at the reasonable assurance level.

Subsequent to the issuance of our consolidated financial statements for the three and nine months ended September 30, 2006, we determined that we had not properly recognized additional net income of $2.3 million within our consolidated financial statements for both the three and nine months ended September 30, 2006. The additional net income was the result of the recognition of an unrealized gain with respect to certain financial derivative instruments under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Specifically, we entered into a significant number of option instruments (a combination of puts purchased and calls sold that are commonly known as costless collars) in September 2006 to hedge our exposure to movements in commodity prices that were not appropriately valued within our consolidated financial statements under the provisions of SFAS No. 133. While the costless collars were valued appropriately with regard to their intrinsic value, we did not record a fair value for the time-value component of the derivative instruments. All of our other derivative instruments that were in effect during 2006 have been appropriately recorded within our consolidated financial statements.

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 6. EXHIBITS (RESTATED)

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)]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to 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.

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SIGNATURES

ATLAS PIPELINE PARTNERS, L.P.

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	By:	Atlas Pipeline Partners GP, LLC, its General Partner
Date: March 14, 2007	By:	/s/ EDWARD E. COHEN Edward E. Cohen Chairman of the Managing Board of the General Partner (Chief Executive Officer of the General Partner)
Date: March 14, 2007	By:	/s/ MICHAEL L.STAINES Michael L. Staines President, Chief Operating Officer and Managing Board Member of the General Partner
Date: March 14, 2007	By:	/s/ MATTHEW A. JONES Matthew A. Jones Chief Financial Officer of the General Partner
Date: March 14, 2007	By:	/s/ SEAN P. MCGRATH Sean P. McGrath Chief Accounting Officer of the General Partner