ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 08, 2007

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

(Mark One)

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

For the quarterly period ended June 30, 2007

OR

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

For the transition period from __________ to __________

Commission file number:1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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 o Accelerated filer þ Non-accelerated filer o

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

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
INDEX TO QUARTERLY REPORT
ON FORM 10-Q

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

	June 30, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,435	$ 1,795
Accounts receivable affiliates	3,908	7,601
Accounts receivable	48,409	51,192
Current portion of derivative asset		5,437
Prepaid expenses and other	4,286	10,444
Total current assets	59,038	76,469
Property, plant and equipment, net	638,479	607,097
Long-term derivative asset		305
Intangible assets, net	24,744	25,530
Goodwill	63,441	63,441
Other assets, net	13,464	14,042
	$ 799,166	$ 786,884
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 39	$ 71
Accounts payable	14,311	18,624
Accrued liabilities	10,271	6,410
Distribution payable	15,706	
Current portion of derivative liability	32,152	17,362
Accrued producer liabilities	29,999	32,766
Total current liabilities	102,478	75,233
Long-term derivative liability	26,223	8,505
Long-term debt, less current portion	368,464	324,012

Commitments and contingencies		
Partners capital:		
Preferred limited partner s interests	37,097	39,381
Common limited partners interests	288,850	350,805
General partner s interest	5,563	11,034
Accumulated other comprehensive loss	(29,509)	(22,086)
Total partners capital	302,001	379,134
	$ 799,166	$ 786,884

See accompanying notes to consolidated financial statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Revenue:				
Natural gas and liquids	$ 104,792	$ 95,609	$ 206,968	$ 196,086
Transportation and compression affiliates	8,458	7,834	16,178	15,708
Transportation and compression third parties	10,588	5,379	20,426	14,156
Other income (loss)	(28,423)	679	(30,620)	1,361
Total revenue and other income (loss)	95,415	109,501	212,952	227,311
Costs and expenses:				
Natural gas and liquids	87,102	77,006	174,912	162,898
Plant operating	4,515	3,926	9,045	7,153
Transportation and compression	3,210	2,849	6,322	4,925
General and administrative	6,608	4,181	12,311	8,396
Compensation reimbursement affiliates	798	885	1,428	1,605
Depreciation and amortization	6,671	5,258	13,205	10,533
Interest	7,327	6,154	14,086	12,491
Minority interest in NOARK		(451)		118
Total costs and expenses	116,231	99,808	231,309	208,119
Net income (loss)	(20,816)	9,693	(18,357)	19,192
Preferred unit dividend effect	(3,756)		(3,756)	
Preferred unit imputed dividend cost	(735)	(540)	(1,234)	(635)
Net income (loss) attributable to common limited partners and the general partner	$ (25,307)	$ 9,153	$ (23,347)	$ 18,557
Allocation of net income (loss) attributable to common Limited partners and the general partner:				
Common limited partners interest	$ (28,728)	$ 5,299	$ (30,612)	$ 11,105
General partner s interest	3,421	3,854	7,265	7,452
Net income (loss) attributable to common limited partners and the general partner	$ (25,307)	$ 9,153	$ (23,347)	$ 18,557

Net income (loss) attributable to common limited partners per unit:								
Basic	$	(2.20)	$	0.41	$	(2.34)	$	0.88
Diluted	$	(2.20)	$	0.41	$	(2.34)	$	0.87
Weighted average common limited partner units outstanding:								
Basic		13,080		12,824		13,080		12,687
Diluted		13,080		12,979		13,080		12,833

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
FOR THE SIX MONTHS ENDED JUNE 30, 2007
(in thousands, except unit data)
(Unaudited)

	Number of Limited Partner Units Preferred	Number of Limited Partner Units Common	Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Total Partners Capital
Balance at January 1, 2007	40,000	13,080,418	$ 39,381	$ 350,805	$ 11,034	$ (22,086)	$ 379,134
Preferred unit dividend			(8,524)				(8,524)
Costs incurred related to issuance of preferred dividend			(7)				(7)
Costs incurred related to issuance of common units				(40)			(40)
Unissued common units under incentive plans				4,302			4,302
Costs incurred related to issuance of units under incentive plans				(40)			(40)
Distributions paid and payable to common limited partners and the general partner				(33,878)	(12,711)		(46,589)
Distribution equivalent rights paid and payable on unissued units under incentive plans				(455)			(455)
Other comprehensive loss						(7,423)	(7,423)
Net loss			4,990	(30,612)	7,265		(18,357)
Balance at June 30, 2007	40,000	13,080,418	$ 35,840	$ 290,082	$ 5,588	$ (29,509)	$ 302,001

See accompanying notes to consolidated financial statements

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

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (18,357)	$ 19,192
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	13,205	10,533
Non-cash loss (gain) on derivative value	30,826	(256)
Non-cash compensation expense	4,262	2,502
Amortization of deferred finance costs	1,068	1,205
Minority interest in NOARK		118
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable and prepaid expenses and other	8,496	8,577
Accounts payable and accrued liabilities	(3,218)	(18,249)
Accounts payable and accounts receivable affiliates	3,693	314
Net cash provided by operating activities	39,975	23,936
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net cash paid for acquisition		(30,000)
Capital expenditures	(43,395)	(35,812)
Other	216	159
Net cash used in investing activities	(43,179)	(65,653)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from issuance of debt	8,524	36,655
Payment of preferred unit dividend	(8,524)	
Repayment of debt		(39,000)
Borrowings under credit facility	118,000	9,500
Repayments under credit facility	(82,000)	(19,000)
Net proceeds from issuance of common limited partner units		19,769
Net proceeds from issuance of preferred limited partner units		39,970
General partner capital contribution		1,206
Distributions paid to common limited partners and the general partner	(30,883)	(28,362)
Other	(1,273)	(697)
Net cash provided by financing activities	3,844	20,041
Net change in cash and cash equivalents	640	(21,676)

Cash and cash equivalents, beginning of period	1,795	34,237
Cash and cash equivalents, end of period	$ 2,435	$ 12,561

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2007
(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the transmission, gathering and processing of natural gas. The Partnership s operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 2% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 1,641,026 limited partner units in the Partnership which have not been registered with the Securities and Exchange Commission and, therefore, their resale in the public market is subject to restrictions under the Securities Act. At June 30, 2007, the Partnership had 13,080,418 common limited partnership units, including 1,641,026 unregistered common units held by the General Partner, and 40,000 $1,000 par value cumulative convertible preferred limited partnership units outstanding (see Note 4 and Note 15).

The Partnership s General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas America, Inc. and its affiliates (Atlas America), a publicly-traded company (NASDAQ: ATLS), had an 82.9% ownership interest in AHD s outstanding common units at June 30, 2007. Atlas America also had a 49.0% ownership interest in the outstanding common units of Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a publicly-traded company (NYSE: ATN) focused on the development of natural gas and oil in the Appalachian basin. Substantially all of the natural gas the Partnership transports in the Appalachian Basin is derived from wells operated by Atlas Energy.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2006 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management s opinion, all adjustments necessary for a fair presentation of the Partnership s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2006. The results of operations for the three and six month periods ended June 30, 2007 may not necessarily be indicative of the results of operations for the full year ending December 31, 2007.

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

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership s significant accounting policies is included in its audited consolidated financial statements and notes thereto in its annual report on Form 10-K for the year ended December 31, 2006.

Principles of Consolidation and Minority Interest

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

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

Use of Estimates

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

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented for the three and six months ended June 30, 2007 represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners, which is determined after the deduction of the general partner s and the preferred unitholder s interests, by the weighted average number of common limited partner units outstanding during the period. The general partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 5), with a priority allocation of net income in an amount equal to the general partner s incentive distributions, in accordance with the partnership agreement, and the remaining net income or loss allocated with respect to the general partner s and limited partners ownership interests. Diluted net income attributable to common limited partners per unit is calculated by dividing net income attributable to common limited partners by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of phantom unit awards, as calculated by the treasury stock method, and the dilutive effect of convertible securities. 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 June 30,		**Six Months Ended June 30,**	
	2007	**2006**	**2007**	**2006**
Weighted average number of common limited partner units basic	13,080	12,824	13,080	12,687
Add: effect of dilutive unit incentive awards [1]		155		146
Weighted average number of common limited partner units diluted	13,080	12,979	13,080	12,833

(1) For the three and six months ended June 30, 2007, approximately 271,000 and 258,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

For the periods presented in the table above, potential common limited partner units issuable upon conversion of the Partnership s 40,000 $1000 par value cumulative convertible preferred limited partner units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive (see Note 4 for additional information regarding the conversion features of the preferred limited partner units).

Comprehensive Income (Loss)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Net income (loss)	$ (20,816)	$ 9,693	$ (18,357)	$ 19,192
Preferred unit dividend	(3,756)		(3,756)	
Preferred unit imputed dividend cost	(735)	(540)	(1,234)	(635)
Net (loss) income attributable to common limited partners and the general partner	(25,307)	9,153	(23,347)	18,557
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as hedges	(9,453)	(18,845)	(18,120)	(18,471)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Add: adjustment for realized losses reclassified to net income (loss)	7,650	3,222	10,697	5,622
Total other comprehensive (loss) income	(1,803)	(15,623)	(7,423)	(12,849)
Comprehensive (loss) income	$ (27,110)	$ (6,470)	$ (30,770)	$ 5,708

Revenue Recognition

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

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

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. The Partnership s revenue is a function of the volume of natural gas that it gathers and processes and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this situation, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership owns a percentage of that commodity and is directly subject to its market value.

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

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 June 30, 2007 and December 31,

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2006 of $11.2 million and $20.2 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 8.0% for both the three and six months ended June 30, 2007 and 8.1% for both the three and six months ended June 30, 2006. The amount of interest capitalized was $0.4 million and $0.6 million for the three months ended June 30, 2007 and 2006, respectively, and $1.0 million for both the six months ended June 30, 2007 and 2006.

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 June 30, 2007 and December 31, 2006 (in thousands):

	June 30, 2007	December 31, 2006	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,810	$ 12,390	8
Customer relationships	17,260	17,260	20
	$ 30,070	$ 29,650	
Accumulated Amortization:			
Customer contracts	$ (3,420)	$ (2,646)	
Customer relationships	(1,906)	(1,474)	
	$ (5,326)	$ (4,120)	
Net Carrying Amount:			
Customer contracts	$ 9,390	$ 9,744	
Customer relationships	15,354	15,786	
	$ 24,744	$ 25,530	

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 based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6).

Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets (SFAS No. 142) requires that intangible assets with finite useful lives be amortized over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition. Amortization expense on intangible assets was $0.6 million and $1.2 million for the three months ended June 30, 2007 and 2006, respectively, and $1.2 million and $2.3 million for the six months ended June 30, 2007 and 2006, respectively. Amortization expense related to intangible assets is estimated to be $2.5 million for each of the next five calendar years commencing in 2008.

Goodwill

At June 30, 2007 and December 31, 2006, the Partnership had $63.4 million of goodwill recorded in connection with consummated acquisitions (see Note 8). The changes in the carrying amount of goodwill for the six months ended June 30, 2007 and 2006 were as follows (in thousands):

	Six Months Ended June 30,	
	2007	**2006**
Balance, beginning of period	$ 63,441	$ 111,446
Goodwill acquired remaining 25% interest in NOARK		30,195
Reduction in minority interest deficit acquired		(118)
Purchase price allocation adjustment NOARK		(314)
Balance, end of period	$ 63,441	$ 141,209

During the third quarter of 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to goodwill based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment (see Note 6). The Partnership tests its goodwill for impairment at each year end by comparing enterprise fair values to carrying values. The evaluation of impairment under SFAS No. 142 requires the use of projections, estimates and assumptions as to the future performance of the Partnership s operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections, resulting in revisions to the Partnership s assumptions and, if required, recognition of an impairment loss. The Partnership s test of goodwill at December 31, 2006 resulted in no impairment, and no impairment indicators have been noted as of June 30, 2007. The Partnership will continue to evaluate its goodwill at least annually and if impairment indicators arise, and will reflect the impairment of goodwill, if any, within the consolidated statement of income for the period in which the impairment is indicated.

New Accounting Standards

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

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

NOTE 3 COMMON UNIT EQUITY OFFERING

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

NOTE 4 PREFERRED UNIT EQUITY OFFERING

On March 13, 2006, the Partnership entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), 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 for $10.0 million on May 19, 2006, pursuant to the Partnership s right under the agreement to require Sunlight Capital to purchase such additional units. The preferred units were originally entitled to receive dividends of 6.5% per annum commencing on March 13, 2007 and were to have been accrued and paid quarterly on the same date as the distribution payment date for the Partnership s common units. On April 18, 2007, the Partnership and Sunlight Capital agreed to amend the terms of the preferred units effective as of that date. The terms of the preferred units were amended to entitle them to receive dividends of 6.5% per annum commencing on March 13, 2008 and to be convertible, at Sunlight Capital s option, into common units commencing on the date immediately following the first record date for common unit distributions after March 13, 2008 at a conversion price equal to the lesser of $43.00 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 applicable redemption price under the amended agreement was increased to $53.82.

In consideration of Sunlight Capital s consent to the amendment of the preferred units, the Partnership issued $8.5 million of its 8.125% senior unsecured notes due 2015 (the Notes) (see Note 10) to Sunlight Capital. The Partnership filed, pursuant to the Registration Rights Agreement, an exchange offer registration statement to exchange the Notes for publicly tradable notes. The registration statement was declared effective by the SEC on July 17, 2007. The Partnership must complete the exchange offer by September 15, 2007 or, if it fails to do so, the Notes will accrue additional interest of 1% per annum for each 90-day period the Partnership is in default, up to a maximum amount of 3% per annum. The Partnership recorded the Notes as long-term debt and a preferred unit dividend within partners capital, and has reduced net income attributable to common limited partners and the general partner by $3.8 million of this amount, which is the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the preferred unitholder, on its consolidated statements of income.

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 originally recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. The imputed dividend cost of $2.4 million was the result of the preferred units not having a dividend yield during the first year after their issuance on March 13, 2006 and was amortized in full as of March 12, 2007. As a result of the amended agreement, the Partnership recognized an imputed dividend cost of $2.5 million that will be amortized during the year commencing March 13, 2007 and is based upon the present value of the net proceeds received using the 6.5% stated yield.

Amortization of the imputed dividend cost, which is presented as a reduction of net income to determine net income attributable to common limited partners and the general partner on its consolidated statements of income, was $0.7 million and $0.5 million for the three months ended June 30, 2007 and 2006, respectively, and $1.2 million and $0.6 million for the six months ended June 30, 2007 and 2006, respectively. If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership s consolidated balance sheet. Dividends accrued and paid on the preferred units and the premium paid upon their redemption, if any, will be recognized as a reduction to the Partnership s net income in determining net income attributable to common unitholders and the general partner.

The net proceeds from the initial issuance of the preferred units were used to fund a portion of the Partnership s capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under the Partnership s credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK.

NOTE 5 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of its available cash (as defined in its partnership agreement) for that quarter. If distributions in any quarter exceed specified target levels, the general partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Distributions declared by the Partnership for the period from January 1, 2006 through June 30, 2007 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 14, 2006	December 31, 2005	$0.83	$10,416	$3,638
May 15, 2006	March 31, 2006	$0.84	$10,541	$3,766
August 14, 2006	June 30, 2006	$0.85	$11,118	$4,059
November 14, 2006	September 30, 2006	$0.85	$11,118	$4,059
February 14, 2007	December 31, 2006	$0.86	$11,249	$4,193
May 15, 2007	March 31, 2007	$0.86	$11,249	$4,193
August 14, 2007	June 30, 2007	$0.87	$11,380	$4,326

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2007	December 31, 2006	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 651,804	$ 611,575	15 40
Rights of way	32,513	30,401	20 40
Buildings	4,078	3,800	40
Furniture and equipment	3,524	3,288	3 7
Other	2,538	2,081	3 10
	694,457	651,145	
Less accumulated depreciation	(55,978)	(44,048)	
	$ 638,479	$ 607,097	

In May 2006, the Partnership acquired the remaining 25% ownership interest in NOARK for $69.0 million in cash, including the repayment of the $39.0 million of NOARK notes at the date of acquisition (see Note 8). The Partnership acquired the initial 75% ownership interest in NOARK for approximately $179.8 million in October 2005 (see Note 8). During the third quarter of 2006, the Partnership adjusted the preliminary purchase price allocation for the NOARK acquisition and reduced the estimated amount allocated to customer contracts and customer relationships intangible assets and goodwill based upon the findings of an independent valuation firm (see Note 8) and allocated additional amounts to property, plant and equipment.

NOTE 7 OTHER ASSETS

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

	June 30, 2007	December 31, 2006
Deferred finance costs, net of accumulated amortization of $5,040 and $3,972 at June 30, 2007 and December 31, 2006, respectively	$ 12,133	$ 12,530
Security deposits	1,296	1,415
Other	35	97
	$ 13,464	$ 14,042

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

NOTE 8 ACQUISITIONS

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

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

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

NOTE 9 DERIVATIVE INSTRUMENTS

The Partnership enters into financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133).

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

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value in partners capital as accumulated other comprehensive (loss) income, and reclassifies them to natural gas and liquids revenue within natural gas and liquids revenue in its consolidated statements of income as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, the Partnership recognizes changes in fair value within other income (loss) in its consolidated statements of income as they occur. At June 30, 2007 and December 31, 2006, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $58.4 million and $20.1 million, respectively. Of the $29.5 million of net loss in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet at June 30, 2007, if the fair values of the instruments remain at current market values, the Partnership will reclassify $22.4 million of losses to natural gas and liquids revenue in its consolidated statements of income over the next twelve month period as these contracts expire, and $7.1 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes.

On June 3, 2007, the Partnership signed definitive agreements to acquire control of certain natural gas gathering systems and processing plants located in Oklahoma and Texas (see Note 15). In connection with certain additional agreements entered into to finance this transaction, the Partnership agreed as a condition precedent to closing that it would hedge 80% of its projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, the Partnership entered into derivative instruments to hedge 80% of the projected production of the assets to be acquired as required under the financing agreements. The production volume of the assets to be acquired was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the assets had not yet been completed. Accordingly, the Partnership recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in its consolidated statements of income. The Partnership recognized a non-cash loss of $19.8 million related to the change in value of these derivatives for the three and six months ended June 30, 2007. Upon closing of the acquisition in July 2007, the production volume of the assets acquired was considered probable forecasted production under SFAS No. 133 and the Partnership evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

Ineffective hedge gains or losses are recorded within other income (loss) 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 $7.7 million and $3.2 million for the three months ended June 30, 2007 and 2006, respectively, and losses of $10.7 million and $5.6 million for the six months ended June 30, 2007 and 2006, respectively, within natural gas and liquids revenue in its consolidated statements of income related to the settlement of qualifying hedge instruments. The Partnership recognized losses of $18.8 million and $9.7 million within other income (loss) in its consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the three months ended June 30, 2007. The Partnership recognized losses of $20.1 million and $10.7 million within other income (loss) in its consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the six months ended June 30, 2007. The losses recognized related to the change in market value of non-qualifying derivatives during the three and six months ended June 30, 2007 were principally due to derivative instruments entered into to hedge the projected production of the acquisition mentioned previously (see Note 15). The Partnership recognized gains of $0.4 million and $0.9 million for the three and six months ended June 30, 2006, respectively, within other income (loss) in its consolidated statements of income related to the change in market value of the ineffective portion of qualifying derivatives only. For the three and six months ended June 30, 2006, the Partnership did not have any non-qualifying derivatives.

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

As of June 30, 2007, the Partnership had the following NGLs, natural gas, and crude oil volumes hedged, including derivatives that do not qualify for hedge accounting:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability(1)
	(gallons)	(per gallon)	(in thousands)
2007	57,204,000	$ 0.893	$ (8,605)
2008	33,012,000	0.697	(7,511)
2009	8,568,000	0.746	(1,110)
			$ (17,226)

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Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)(2) (in thousands)	Option Type
2007	1,275,000	78,681,000	$ 60.00	$ 782	Puts purchased
2007	1,275,000	78,681,000	75.18	(2,543)	Calls sold
2008	4,269,600	260,692,000	60.00	12,546	Puts purchased
2008	4,269,600	260,692,000	79.20	(17,100)	Calls sold
2009	4,752,000	290,364,000	60.00	19,667	Puts purchased
2009	4,752,000	290,364,000	78.68	(25,638)	Calls sold
2010	2,413,500	149,009,000	60.00	11,104	Puts purchased
2010	2,413,500	149,009,000	77.28	(14,296)	Calls sold
				$ (15,478)	

Natural Gas Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu) (3)	Fair Value Liability(2) (in thousands)
2007	540,000	$ 7.255	$ (40)
2008	240,000	7.270	(266)
2009	480,000	8.000	(265)
			$ (571)

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Asset/(Liability)(2) (in thousands)
2007	2,820,000	$ (0.771)	$ (157)
2008	4,440,000	(0.671)	(294)
2009	4,920,000	(0.558)	(215)
2010	2,220,000	(0.575)	33
			$ (633)

Natural Gas Purchases

Production Period Ended December 31,	Volumes (mmbtu)[3]	Average Fixed Price (per mmbtu)[3]	Fair Value Liability[2] (in thousands)
2007	5,460,000	$ 8.593[4]	$ (8,582)
2008	11,016,000	8.951[5]	(6,626)
2009	10,320,000	8.687	(1,390)
2010	4,380,000	8.635	(515)
			$ (17,113)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)[3]	Average Fixed Price (per mmbtu)[3]	Fair Value Liability[2] (in thousands)
2007	7,740,000	$ (1.036)	$ (73)
2008	15,216,000	(1.125)	(599)
2009	14,760,000	(0.659)	(1,299)
2010	6,600,000	(0.560)	(1,188)
			$ (3,159)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability[2] (in thousands)
2007	37,700	$ 56.249	$ (561)
2008	65,400	59.424	(842)
2009	33,000	62.700	(321)
			$ (1,724)

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability)[2] (in thousands)	Option Type
2007	324,600	60.000	223	Puts purchased
2007	324,600	75.256	(656)	Calls sold
2008	691,800	60.000	1,804	Puts purchased
2008	691,800	78.004	(3,025)	Calls sold
2009	738,000	60.000	3,045	Puts purchased
2009	738,000	80.622	(3,549)	Calls sold
2010	402,000	60.000	1,753	Puts purchased
2010	402,000	79.341	(1,947)	Calls sold
2011	30,000	60.000	164	Puts purchased
2011	30,000	74.500	(223)	Calls sold
2012	30,000	60.000	177	Puts purchased
2012	30,000	73.900	(237)	Calls sold
			$ (2,471)	
		Total net liability	$ (58,375)	

(1) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward

NYMEX natural gas, light crude and propane prices.

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

(3) Mmbtu represents million British Thermal Units.

(4) Includes the Partnership s premium received from its sale of an option for it to sell 2,400,000 mmbtu of natural gas at an average price of $15.00 per mmbtu for the year ended December 31, 2007.

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

NOTE 10 DEBT

Total debt consists of the following (in thousands):

	June 30,

	2007	December 31, 2006
Revolving credit facility	$ 74,000	$ 38,000
Senior notes	294,446	285,977
Other debt	57	106
	368,503	324,083
Less current maturities	(39)	(71)
	$ 368,464	$ 324,012

Credit Facility

The Partnership has a $225.0 million credit facility with a syndicate of banks which matures in June 2011. The credit facility bears interest, at the Partnership s option, at either (i) adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding credit facility borrowings at June 30, 2007 was 7.6%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $7.1 million was outstanding at June 30, 2007. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet. Borrowings under the credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its wholly-owned subsidiaries, and by the guaranty of each of its wholly-owned subsidiaries. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is in compliance with these covenants as of June 30, 2007.

The events which constitute an event of default for the Partnership s credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner. The credit facility requires the Partnership to maintain a ratio of senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.25 to 1.0; and an interest coverage ratio (as defined in the credit facility) of not less than 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of June 30, 2007, the Partnership s ratio of senior secured debt to EBITDA was 1.0 to 1.0, its funded debt ratio was 4.6 to 1.0 and its interest coverage ratio was 3.4 to 1.0.

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

Senior Notes

At June 30, 2007, the Partnership has $293.5 million of 10-year, 8.125% senior unsecured notes (Senior Notes) outstanding, net of unamortized premium received of $0.9 million. Interest on the Senior Notes is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time on or after December 15, 2010 at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The Senior Notes are also redeemable at any time prior to December 15, 2010 at stated redemption prices, together with accrued and unpaid interest to the date of redemption. In addition, prior to December 15, 2008, the Partnership may redeem up to 35% of the aggregate principal amount of the Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes are also subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under the Credit Facility.

On April 18, 2007, the Partnership issued Sunlight Capital $8.5 million of its Senior Notes in consideration of their consent to the amendment of the Partnership s preferred units agreement (see Note 4). The Partnership filed, pursuant to the Registration Rights Agreement, an exchange offer registration statement to exchange the Notes for publicly tradable notes. The registration statement was declared effective by the SEC on July 17, 2007. The Partnership must complete the exchange offer by September 15, 2007 or, if it fails to do so, the Notes will accrue additional interest of 1% per annum for each 90-day period the Partnership is in default, up to a maximum amount of 3% per annum.

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 June 30, 2007.

NOTE 11 COMMITMENTS AND CONTINGENCIES

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

As of June 30, 2007, the Partnership is committed to expend approximately $76.9 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

NOTE 12 STOCK COMPENSATION

Long-Term Incentive Plan

The Partnership has a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner s affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by General Partner s managing board. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units. Only phantom units have been granted under the LTIP through June 30, 2007.

A phantom unit entitles a grantee to receive a common unit upon vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. In addition, the Committee may grant a participant a distribution equivalent right (DER), which is the right to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. A unit option entitles the grantee to purchase the Partnership s common limited partner units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through June 30, 2007, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined in the LTIP. Of the units outstanding under the LTIP at June 30, 2007, 88,914 units will vest within the following twelve months. All units outstanding under the LTIP at June 30 2007 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs were $0.2 million and $0.1 million during the three months ended June 30, 2007 and 2006, respectively, and $0.3 million and $0.2 million during the six months ended June 30, 2007 and 2006, respectively. These amounts were recorded as reductions of Partners Capital on the consolidated balance sheet.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Outstanding, beginning of period	183,859	110,856	159,067	110,128
Granted[1]	303	363	25,095	1,091
Matured				
Forfeited				
Outstanding, end of period	184,162	111,219	184,162	111,219
Non-cash compensation expense recognized (in thousands)	$ 973	$ 321	$ 1,874	$ 844

(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 $49.42 and $41.29 for awards granted for the three months ended June 30, 2007 and 2006, respectively, and $50.09 and $41.17 for awards granted for the six months ended June 30, 2007 and 2006, respectively.

At June 30, 2007, the Partnership had approximately $3.9 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 personnel 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 $1.5 million and $0.9 million for the three months ended June 30, 2007 and 2006, respectively, and $2.4 million and $1.7 million for the six months ended June 30, 2007 and 2006, 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 June 30, 2007, 221,813 common unit awards are ultimately expected to be issued under these agreements. At June 30, 2007, the Partnership had approximately $1.1 million of unrecognized compensation expense related to the unvested portion of these awards based upon management s estimate of performance target achievement. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method.

NOTE 13 RELATED PARTY TRANSACTIONS

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

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates $0.8 million and $0.9 million for the three months ended June 30, 2007 and 2006, respectively, and $1.4 million and $1.6 million for six months ended June 30, 2007 and 2006, respectively, for compensation and benefits related to their executive officers. For the three months ended June 30, 2007 and 2006, direct reimbursements were $6.2 million and $6.6 million, respectively, and $12.2 million and $13.1 million for the six months ended June 30, 2007 and 2006, respectively, including certain costs that have been capitalized by the Partnership. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

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

NOTE 14 OPERATING SEGMENT INFORMATION

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Mid-Continent				
Revenue:				
Natural gas and liquids	$ 104,792	$ 95,609	$ 206,968	$ 196,086
Transportation and compression	10,571	5,360	20,390	14,110
Other income (loss)	(28,506)	414	(30,785)	955
Total revenue and other income (loss)	86,857	101,383	196,573	211,151
Costs and expenses:				
Natural gas and liquids	87,102	77,006	174,912	162,898
Plant operating	4,515	3,926	9,045	7,153
Transportation and compression	1,780	1,532	3,500	2,640
General and administrative	4,806	2,995	8,700	6,163
Minority interest in NOARK		(451)		118
Depreciation and amortization	5,555	4,375	11,015	8,834
Total costs and expenses	103,758	89,383	207,172	187,806
Segment profit (loss)	$ (16,901)	$ 12,000	$ (10,599)	$ 23,345
Appalachia				
Revenue:				

Transportation and compression	affiliates	$ 8,458	$ 7,834	$ 16,178	$ 15,708
Transportation and compression	third parties	17	19	36	46
Other income		83	265	165	406
Total revenue and other income		8,558	8,118	16,379	16,160

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Costs and expenses:				
Transportation and compression	1,430	1,317	2,822	2,285
General and administrative	1,300	1,035	2,520	1,919
Depreciation and amortization	1,116	883	2,190	1,699
Total costs and expenses	3,846	3,235	7,532	5,903
Segment profit	$ 4,712	$ 4,883	$ 8,847	$ 10,257
Reconciliation of segment profit (loss) to net income (loss):				
Segment profit (loss):				
Mid-Continent	$ (16,901)	$ 12,000	$ (10,599)	$ 23,345
Appalachia	4,712	4,883	8,847	10,257
Total segment profit (loss)	(12,189)	16,883	(1,752)	33,602
Corporate general and administrative expenses	(1,300)	(1,036)	(2,519)	(1,919)
Interest expense	(7,327)	(6,154)	(14,086)	(12,491)
Net income (loss)	$ (20,816)	$ 9,693	$ (18,357)	$ 19,192
Capital Expenditures:				
Mid-Continent	$ 22,017	$ 17,777	$ 37,606	$ 27,198
Appalachia	3,001	4,473	5,789	8,614
	$ 25,018	$ 22,250	$ 43,395	$ 35,812

	June 30, 2007	December 31, 2006
Balance sheet		
Total assets:		
Mid-Continent	$ 746,371	$ 730,791
Appalachia	38,753	42,448
Corporate other	14,042	13,645
	$ 799,166	$ 786,884
Goodwill:		
Mid-Continent	$ 61,136	$ 61,136
Appalachia	2,305	2,305

	$ 63,441	$ 63,441

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Natural gas and liquids:				
Natural gas	$ 37,347	$ 42,035	$ 84,110	$ 98,835
NGLs	60,056	45,083	106,828	83,009
Condensate	2,144	1,739	4,733	3,257
Other (1)	5,245	6,752	11,297	10,985
Total	$ 104,792	$ 95,609	$ 206,968	$ 196,086
Transportation and compression:				
Affiliates	$ 8,459	$ 7,834	$ 16,179	$ 15,708
Third parties	10,587	5,379	20,425	14,156
Total	$ 19,046	$ 13,213	$ 36,604	$ 29,864

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

NOTE 15 SUBSEQUENT EVENT

On July 27, 2007, the Partnership acquired control of Anadarko Petroleum Corporation s (NYSE: APC) (Anadarko) 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its approximate 73% interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Assets). The Chaney Dell System includes 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum System includes 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which the Partnership contributed $1.85 billion and Anadarko contributed the Assets.

In connection with this acquisition, the Partnership has reached an agreement with Pioneer Natural Resources Company (NYSE: PXD Pioneer), which currently holds an approximate 27% interest in the Midkiff/Benedum system, whereby Pioneer will have an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system one year after the closing of the Partnership s acquisition of Anadarko s interest, and up to an additional 7.5% interest two years after the closing of the Partnership s acquisition of Anadarko s interest. If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49%. Pioneer would pay approximately $230 million for the additional 22% interest if fully exercised. The Partnership will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options.

The Partnership funded the purchase price in part from an $830.0 million senior secured term loan which matures in July 2014 and a new $300.0 million senior secured revolving credit facility that matures in July 2013. Borrowings under the credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, except for the assets owned by the joint venture companies, and by the guaranty of each of its subsidiaries other than the joint venture companies. The Partnership funded the remaining purchase price from the private placement of $1.125 billion of its common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by AHD. AHD, which holds all of the incentive distribution rights in the Partnership, has also agreed to allocate a portion of its future incentive distribution rights to the Partnership in connection with this acquisition. AHD has agreed to allocate up to $5.0 million of incentive distribution rights per quarter to the Partnership for the first 8 quarters after closing of the transaction and up to $3.75 million per quarter after the initial 8 quarter period.

The Partnership signed definitive agreements to acquire control of the Assets on June 3, 2007. In connection with agreements entered into with respect to its new credit facility, term loan and private placement of common units, the Partnership agreed as a condition precedent to closing that it would hedge 80% of its projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, the Partnership entered into derivative instruments to hedge 80% of the projected production of the Assets to be acquired as required under the financing agreements. The production volume of the Assets was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the Assets had not yet been completed. Accordingly, the Partnership recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in its consolidated statements of income. The Partnership recognized a non-cash loss of $19.8 million related to the change in value of these derivatives for the three and six months ended June 30, 2007. Upon closing of the acquisition in July 2007, the production volume of the Assets was considered probable forecasted production under SFAS No. 133 and the Partnership evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

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

Forward-Looking Statements

When used in this Form 10-Q, the words believes, anticipates, expects and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 1A, under the caption Risk Factors , in our annual report on Form 10-K for 2006. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

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

General

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

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

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

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

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

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

Significant Acquisitions

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

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

Subsequent Event Anadarko Acquisition

On July 27, 2007, we acquired control of Anadarko Petroleum Corporation s (NYSE: APC) (Anadarko) 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its approximate 73% interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Assets). The Chaney Dell System includes 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum System includes 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which we contributed $1.85 billion and Anadarko contributed the Assets.

In connection with this acquisition, we have reached an agreement with Pioneer Natural Resources Company (NYSE: PXD Pioneer), which currently holds an approximate 27% interest in the Midkiff/Benedum system, whereby Pioneer will have an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system one year after the closing of our acquisition of Anadarko s interest, and up to an additional 7.5% interest two years after the closing of our acquisition of Anadarko s interest. If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49%. Pioneer would pay approximately $230 million for the additional 22% interest if fully exercised. We will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options.

We funded the purchase price in part from an $830.0 million senior secured term loan which matures in July 2014 and a new $300.0 million senior secured revolving credit facility that matures in July 2013. Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, except for the assets owned by the joint venture companies, and by the guaranty of each of our subsidiaries other than the joint venture companies. We funded the remaining purchase price from the private placement of $1.125 billion of our common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by Atlas Pipeline Holdings, the parent of our general partner. AHD, which holds all of our incentive distribution rights, has also agreed to allocate a portion of its future incentive distribution rights to us in connection with this acquisition. AHD has agreed to allocate up to $5.0 million of incentive distribution rights per quarter to us for the first 8 quarters after closing of the transaction and up to $3.75 million per quarter after the initial 8 quarter period.

We signed definitive agreements to acquire control of the Assets on June 3, 2007. In connection with agreements entered into with respect to our new credit facility, term loan and private placement of common units, we agreed as a condition precedent to closing that we would hedge 80% of our projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, we entered into derivative instruments to hedge 80% of the projected production of the Assets to be acquired as required under the financing agreements. The production volume of the Assets was not considered to be probable forecasted production under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133) at the date these derivatives were entered into because the acquisition of the Assets had not yet been completed. Accordingly, we recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in our consolidated statements of income. We recognized a non-cash loss of $19.8 million related to the change in value of these derivatives for the three and six months ended June 30, 2007. Upon closing of the acquisition in July 2007, the production volume of the Assets was considered probable forecasted production under SFAS No. 133 and we evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

Contractual Revenue Arrangements

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

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

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

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

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

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

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

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

Recent Trends and Uncertainties

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

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

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

We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, excluding the impact of the transactions noted in Subsequent Event Anadarko Acquisition , would result in a change to our consolidated income for the twelve-month period ending June 30, 2008 of approximately $9.3 million.

Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Operating data:				
Appalachia:				
Average throughput volumes mcfd	66,152	63,113	64,352	60,235
Average transportation rate per mcf	$ 1.41	$ 1.34	$ 1.39	$ 1.44
Mid-Continent:				
Velma system:				
Gathered gas volume mcfd	62,788	62,079	61,907	61,401
Processed gas volume mcfd	61,150	59,823	59,836	59,179
Residue gas volume mcfd	47,229	46,647	46,463	46,203
NGL volume bpd	6,697	6,674	6,473	6,505
Condensate volume bpd	212	237	206	212
Elk City/Sweetwater system:				
Gathered gas volume mcfd	308,703	275,865	298,355	264,093
Processed gas volume mcfd	234,896	135,394	221,151	133,187
Residue gas volume mcfd	215,501	122,644	203,288	120,840
NGL volume bpd	9,742	6,237	9,132	5,999
Condensate volume bpd	220	147	270	159
NOARK system:				
Average Ozark Gas Transmission throughput volume mcfd	321,717	243,014	304,400	241,093

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006

Revenue. Natural gas and liquids revenue was $104.8 million for the three months ended June 30, 2007, an increase of $9.2 million from $95.6 million for the three months ended June 30, 2006. The increase was primarily attributable to an increase of $9.7 million from the Elk City/Sweetwater system due primarily to an increase in volumes, including processing volumes from the newly constructed Sweetwater gas plant. Gross natural gas gathered on the Elk City system averaged 308.7 MMcfd for the three months ended June 30, 2007, an increase of 11.9% from the comparable prior year period. Gross natural gas gathered averaged 62.8 MMcfd on the Velma system for the three months ended June 30, 2007, an increase of 1.1% from the comparable prior year period.

Transportation and compression revenue increased to $19.0 million for the three months ended June 30, 2007 compared with $13.2 million for the prior year period. This $5.8 million increase was primarily due to an increase of $4.2 million from the transportation revenues associated with the NOARK system. For the NOARK system, average Ozark Gas Transmission volume was 321.7 MMcfd for the three months ended June 30, 2007, an increase of 32.4% from the prior year comparable period. The Appalachia system s average throughput volume was 66.2 MMcfd for the three months ended June 30, 2007 as compared with 63.1 MMcfd for the three months ended June 30, 2006, an increase of 3.1 MMcfd or 4.8%. The Appalachia system s average transportation rate was $1.41 per Mcf for the three months ended June 30, 2007 compared with $1.34 per Mcf for the prior year period, an increase of $0.07 per Mcf, as a result of higher realized natural gas prices. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system.

Other income (loss), including the impact of non-cash gains and losses recognized on derivatives, was a loss of $28.4 million for the three months ended June 30, 2007, a decrease of $29.1 million from the prior year comparable period. This decrease was due primarily to a $28.9 million unfavorable movement in non-cash derivative gains and losses compared with the prior year as a result of unfavorable movements in commodity prices and the impact of derivatives entered into during June 2007 to hedge the projected production volume of the Anadarko acquisition (see Subsequent Event Anadarko Acquisition). The production volume of the assets to be acquired was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the assets had not yet been completed. Accordingly, we recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in our consolidated statements of income. We recognized a non-cash loss of $19.8 million related to the change in value of these derivatives for the three months ended June 30, 2007. Upon closing of the acquisition in July 2007, the production volume of the assets acquired was considered probable forecasted production under SFAS No. 133 and we evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3, Quantitative and Qualitative Disclosures About Market Risk .

Costs and Expenses. Natural gas and liquids cost of goods sold of $87.1 million and plant operating expenses of $4.5 million for the three months ended June 30, 2007 represented increases of $10.1 million and $0.6 million, respectively, from the comparable prior year amounts due primarily to an increase in gathered and processed natural gas volumes on the Elk City system, which includes contributions from the Sweetwater processing facility. Transportation and compression expenses increased $0.4 million to $3.2 million for the three months ended June 30, 2007 due to higher NOARK and Appalachia system operating and maintenance costs as a result of increased capacity and additional well connections.

General and administrative expenses, including amounts reimbursed to affiliates, increased $2.3 million to $7.4 million for the three months ended June 30, 2007 compared with $5.1 million for the prior year comparable period. This increase was mainly due to a $1.3 million increase in non-cash compensation expense related to vesting of phantom and common unit awards and higher costs associated with managing our business, including management time related to acquisition and capital raising opportunities.

Depreciation and amortization increased to $6.7 million for the three months ended June 30, 2007 compared with $5.3 million for the three months ended June 30, 2006 due primarily to the depreciation associated with our expansion capital expenditures incurred between the periods, including the Sweetwater processing facility.

Interest expense increased to $7.3 million for the three months ended June 30, 2007 as compared with $6.2 million for the comparable prior year period. This $1.1 million increase was primarily due to interest associated with additional borrowings under our credit facility to finance our expansion capital expenditures incurred between the periods.

Minority interest in NOARK was income of $0.5 million for the prior year comparable period and represents Southwestern s 25% ownership interest in the net income of NOARK during the prior year period. We acquired the remaining 25% ownership interest in May 2006.

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

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Revenue. Natural gas and liquids revenue was $207.0 million for the six months ended June 30, 2007, an increase of $10.9 million from $196.1 million for the six months ended June 30, 2006. The increase was primarily attributable to an increase of $26.0 million from the Elk City system due primarily to an increase in volumes, which includes processing volumes from the newly constructed Sweetwater gas plant. This increase was partially offset by a decrease of $16.0 million from the NOARK system due primarily to lower natural gas sales volumes on its gathering systems. Gross natural gas gathered on the Elk City system averaged 298.4 MMcfd for the six months ended June 30, 2007, an increase of 13.0% from the comparable prior year period. Gross natural gas gathered averaged 61.9 MMcfd on the Velma system for the six months ended June 30, 2007, an increase of 0.8% from the comparable prior year period.

Transportation and compression revenue increased to $36.6 million for the six months ended June 30, 2007 compared with $29.9 million for the prior year period. This $6.7 million increase was primarily due to an increase of $5.0 million from the transportation revenues associated with the NOARK system. For the NOARK system, average Ozark Gas Transmission volume was 304.4 MMcfd for the six months ended June 30, 2007, an increase of 26.3% from the prior year comparable period. The Appalachia system s average throughput volume was 64.4 MMcfd for the six months ended June 30, 2007 as compared with 60.2 MMcfd for the six months ended June 30, 2006, an increase of 4.2 MMcfd or 6.8%. The Appalachia system s average transportation rate was $1.39 per Mcf for the six months ended June 30, 2007 compared with $1.44 per Mcf for the prior year period, a decrease of $0.05 per Mcf as a result of lower realized natural gas prices. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system.

Other income (loss), including the impact of non-cash gains and losses recognized on derivatives, was a loss of $30.6 million for the six months ended June 30, 2007, a decrease of $32.0 million from the prior year comparable period. This decrease was due primarily to a $31.8 million unfavorable movement in non-cash derivative gains and losses compared with the prior year as a result of unfavorable movements in commodity prices and the impact of derivatives entered into during June 2007 to hedge the projected production volume of the Anadarko acquisition noted previously (see Subsequent Event Anadarko Acquisition). We recognized a non-cash loss of $19.8 million related to the change in value of these derivatives entered into specifically for the Anadarko acquisition for the three months ended June 30, 2007. We enter into derivative instruments solely to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Item 3, Quantitative and Qualitative Disclosures About Market Risk .

Costs and Expenses. Natural gas and liquids cost of goods sold of $174.9 million and plant operating expenses of $9.0 million for the six months ended June 30, 2007 represented increases of $12.0 million and $1.9 million, respectively, from the comparable prior year amounts due primarily to an increase in gathered and processed natural gas volumes on the Elk City system, which includes contributions from the Sweetwater processing facility, partially offset by a decrease in NOARK gathering system natural gas purchases. Transportation and compression expenses increased $1.4 million to $6.3 million for the six months ended June 30, 2007 due to higher NOARK and Appalachia system operating and maintenance costs as a result of increased capacity and additional well connections.

General and administrative expenses, including amounts reimbursed to affiliates, increased $3.7 million to $13.7 million for the six months ended June 30, 2007 compared with $10.0 million for the prior year comparable period. This increase was mainly due to a $1.8 million increase in non-cash compensation expense related to vesting of phantom and common unit awards and higher costs associated with managing our business, including management time related to acquisition and capital raising opportunities.

Depreciation and amortization increased to $13.2 million for the six months ended June 30, 2007 compared with $10.5 million for the six months ended June 30, 2006 due primarily to the depreciation associated with our expansion capital expenditures incurred between the periods, including the Sweetwater processing facility.

Interest expense increased to $14.1 million for the six months ended June 30, 2007 as compared with $12.5 million for the comparable prior year period. This $1.6 million increase was primarily due to interest associated with additional borrowings under our credit facility to finance our expansion capital expenditures incurred between the periods.

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 June 30, 2007, we had $74.0 million outstanding under our credit facility and $7.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $143.9 million of remaining committed capacity under the $225.0 million credit facility, subject to covenant limitations (see Credit Facility). In addition to the availability under the credit facility, we have a universal shelf registration statement on file with the Securities and Exchange Commission, which allows us to issue equity or debt securities (see Shelf Registration Statement), of which $352.1 million remains available at June 30, 2007. At June 30, 2007, we had a working capital deficit of $43.4 million compared with $1.2 million working capital surplus at December 31, 2006. This decrease was primarily due to an increase in the current portion of our net hedge liability between periods, which is the result of changes in commodity prices after we entered into the hedges, and the recognition of a $15.7 million distribution payable at June 30, 2007. We believe that we have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, unitholder distributions, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cashflow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings and the issuance of additional limited partner units.

Cash Flows Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Net cash provided by operating activities of $40.0 million for the six months ended June 30, 2007 represented an increase of $16.1 million from $23.9 million for the comparable prior year period. The increase was derived principally from a $31.1 million change in non-cash derivative gains and losses, an $18.3 million increase in cash resulting from working capital changes and a $2.7 million increase in depreciation and amortization, partially offset by a $37.5 million decrease in net income.

Net cash used in investing activities was $43.2 million for the six months ended June 30, 2007, a decrease of $22.5 million from $65.7 million for the comparable prior year period. This decrease was principally due to $30.0 million of net cash paid for acquisitions in the prior year period, partially offset by a $7.6 million increase in capital expenditures. In May 2006, we acquired the remaining 25% ownership interest in NOARK from Southwestern. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities was $3.8 million for the six months ended June 30, 2007, a decrease of $16.2 million from $20.0 million of net cash provided by financing activities for the comparable prior year period. This decrease was principally due to a $28.1 million decrease in net proceeds from the issuance of long-term debt, a $40.0 million decrease in net proceeds from the issuance of our cumulative convertible preferred units, and a $19.8 million decrease in the net proceeds from the issuance of our common units. These amounts were partially offset by a $45.5 million increase in net borrowings under our credit facility and a $39.0 million decrease in repayments of long-term debt.

Capital Requirements

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

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Maintenance capital expenditures	$ 700	$ 917	$ 1,472	$ 2,078
Expansion capital expenditures	24,318	21,333	41,923	33,734
Total	$ 25,018	$ 22,250	$ 43,395	$ 35,812

Expansion capital expenditures increased to $24.3 million and $41.9 million for the three and six months ended June 30, 2007, respectively, due principally to expansions of the Appalachia, Velma and Elk City/Sweetwater gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. Maintenance capital expenditures for the three and six months ended June 30, 2007 decreased to $0.7 million and $1.5 million, respectively, compared with the prior year comparable period due to fluctuations in the timing of scheduled maintenance activity. As of June 30, 2007, we are committed to expend approximately $76.9 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Partnership Distributions

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

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

Available cash is initially distributed 98% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. The general partner s incentive distributions declared for three and six months ended June 30, 2007 was $4.0 million and $7.9 million, respectively.

Common Equity Offering

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

Shelf Registration Statement

We have an effective shelf registration statement with the Securities and Exchange Commission that permits us to periodically issue equity and debt securities for a total value of up to $500 million. As of June 30, 2007, $352.1 million remains available for issuance under the shelf registration statement. However, the amount, type and timing of any offerings will depend upon, among other things, our funding requirements, prevailing market conditions, and compliance with our credit facility covenants.

Private Placement of Convertible Preferred Units

On March 13, 2006, we entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), 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 for $10.0 million on May 19, 2006, pursuant to our right under the agreement to require Sunlight Capital to purchase such additional units. The preferred units were originally entitled to receive dividends of 6.5% per annum commencing on March 13, 2007 and were to have been accrued and paid quarterly on the same date as the distribution payment date our common units. On April 18, 2007, we and Sunlight Capital agreed to amend the terms of the preferred units effective as of that date. The terms of the preferred units were amended to entitle them to receive dividends of 6.5% per annum commencing on March 13, 2008 and to be convertible, at Sunlight Capital s option, into common units commencing on the date immediately following the first record date for common unit distributions after March 13, 2008 at a conversion price equal to the lesser of $43.00 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. The applicable redemption price under the amended agreement was increased to $53.82.

In consideration of Sunlight Capital s consent to the amendment of the preferred units, we issued $8.5 million of 8.125% senior unsecured notes due 2015 (the Notes) to Sunlight Capital. We filed, pursuant to the Registration Rights Agreement, an exchange offer registration statement to exchange the Notes for publicly tradable notes. The registration statement was declared effective by the SEC on July 17, 2007. We must complete the exchange offer by September 15, 2007 or, if we fail to do so, the Notes will accrue additional interest of 1% per annum for each 90-day period we are in default, up to a maximum amount of 3% per annum. We recorded the Notes as long-term debt and a preferred unit dividend within partners capital. We have also reduced net income attributable to common limited partners and the general partner by $3.8 million of the $8.5 million preferred unit dividend, which is the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the preferred unitholder, on our consolidated statements of income.

The net proceeds from the initial issuance of the preferred units were used to fund a portion of the Partnership s capital expenditures in 2006, including the construction of the Sweetwater gas plant and related gathering system. The proceeds from the issuance of the additional 10,000 preferred units were used to reduce indebtedness under the Partnership s credit facility incurred in connection with the acquisition of the remaining 25% ownership interest in NOARK.

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 June 30, 2007 was 8.0%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $7.1 million was outstanding at June 30, 2007. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet. Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our wholly-owned subsidiaries, and by the guaranty of each of our wholly-owned subsidiaries. The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are in compliance with these covenants as of June 30, 2007.

The events which constitute an event of default are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against us in excess of a specified amount, and a change of control of our general partner. The credit facility requires us to maintain a ratio of senior secured debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) of not more than 4.0 to 1.0; a funded debt (as defined in the credit facility) to EBITDA ratio of not more than 5.25 to 1.0; and an interest coverage ratio (as defined in the credit facility) of not less than 3.0 to 1.0. The credit facility defines EBITDA to include pro forma adjustments, acceptable to the administrator of the facility, following material acquisitions. As of June 30, 2007, our ratio of senior secured debt to EBITDA was 1.0 to 1.0, our funded debt ratio was 4.6 to 1.0 and our interest coverage ratio was 3.4 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

At June 30, 2007, we have $293.5 million of 10-year, 8.125% senior unsecured notes (Senior Notes) outstanding, net of unamortized premium received of $0.9 million. 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.

On April 18, 2007, we issued Sunlight Capital $8.5 million of our Senior Notes in consideration of their consent to the amendment of our preferred units agreement. We filed, pursuant to the Registration Rights Agreement, an exchange offer registration statement to exchange the Notes for publicly tradable notes. The registration statement was declared effective by the SEC on July 17, 2007. We must complete the exchange offer by September 15, 2007 or, if we fail to do so, the Notes will accrue additional interest of 1% per annum for each 90-day period we are in default, up to a maximum amount of 3% per annum.

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 June 30, 2007.

NOARK Notes

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

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenues and expenses during the reporting period. Although we believe our estimates are reasonable, actual results could differ from those estimates. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within our Annual Report on Form 10-K for the year ended December 31, 2006, and there have been no material changes to these policies through June 30, 2007.

New Accounting Standards

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodical use of derivative financial instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on June 30, 2007. Only the potential impact of hypothetical assumptions are analyzed. The analysis does not consider other possible effects that could impact our business.

Interest Rate Risk. At June 30, 2007, we had a $225.0 million revolving credit facility ($74.0 million outstanding) to fund the expansion of our existing gathering systems, acquire other natural gas gathering systems and fund working capital movements as needed. The weighted average interest rate for these borrowings was 7.6% at June 30, 2007. Holding all other variables constant, a 1% change in interest rates would change interest expense by $0.7 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of commodities rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. Based on our current portfolio of natural gas supply contracts, we have long condensate, NGL, and natural gas positions. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, excluding the impact of the transactions noted in Subsequent Event Anadarko

Acquisition , would result in a change to our consolidated income for the twelve-month period ending June 30, 2008 of approximately $9.3 million.

We enter into financial swap and option instruments to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133).

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

Derivatives are recorded on our consolidated balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassify them to natural gas and liquids revenue within our consolidated statements of income as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within other income (loss) in our consolidated statements of income as they occur. At June 30, 2007 and December 31, 2006, we reflected net derivative liabilities on our consolidated balance sheets of $58.4 million and $20.1 million, respectively. Of the $29.5 million of net loss in accumulated other comprehensive loss within partners capital on our consolidated balance sheet at June 30, 2007, if the fair values of the instruments remain at current market values, we will reclassify $22.4 million of losses to natural gas and liquids revenue in our consolidated statements of income over the next twelve month period as these contracts expire, and $7.1 million will be reclassified in later periods. Actual amounts that will be reclassified will vary as a result of future price changes.

On June 3, 2007, we signed definitive agreements to acquire control of certain assets from Anadarko (the Assets see Subsequent Event Anadarko Acquisition). In connection with agreements entered into with respect to our new credit facility, term loan and private placement of common units, we agreed as a condition precedent to closing that we would hedge 80% of our projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, we entered into derivative instruments to hedge 80% of the projected production of the Assets to be acquired as required under the financing agreements. The production volume of the Assets was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the Assets had not yet been completed. Accordingly, we recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in our consolidated statements of income. We recognized a non-cash loss of $19.8 million related to the change in value of these derivatives for the three and six months ended June 30, 2007. Upon closing of the acquisition in July 2007, the production volume of the Assets was considered probable forecasted production under SFAS No. 133 and we evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

Ineffective hedge gains or losses are recorded within other income (loss) 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 $7.7 million and $3.2 million for the three months ended June 30, 2007 and 2006, respectively, and losses of $10.7 million and $5.6 million for the six months ended June 30, 2007 and 2006, respectively, within natural gas and liquids revenue in our consolidated statements of income related to the settlement of qualifying hedge instruments. We recognized losses of $18.8 million and $9.7 million within other income (loss) in our consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the three months ended June 30, 2007. We recognized losses of $20.1 million and $10.7 million within other income (loss) in our consolidated statements of income related to the change in market value of non-qualifying derivatives and the ineffective portion of qualifying derivatives, respectively, for the six months ended June 30, 2007. The losses recognized related to the change in market value of non-qualifying derivatives during the three and six months ended June 30, 2007 were principally due to derivative instruments entered into to hedge the projected production of the acquisition mentioned previously. We recognized gains of $0.4 million and $0.9 million for the three and six months ended June 30, 2006, respectively, within other income (loss) in our consolidated statements of income related to the change in market value of the ineffective portion of qualifying derivatives only. For the three and six months ended June 30, 2006, we did not have any non-qualifying derivatives.

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

As of June 30, 2007, we had the following NGLs, natural gas, and crude oil volumes hedged, including derivatives that do not qualify for hedge accounting:

Natural Gas Liquids Sales

Production Period Ended December 31,	Volumes	Average Fixed Price	Fair Value Liability[1]
	(gallons)	(per gallon)	(in thousands)
2007	57,204,000	$ 0.893	$ (8,605)
2008	33,012,000	0.697	(7,511)
2009	8,568,000	0.746	(1,110)
			$ (17,226)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume	Associated NGL Volume	Average Crude Strike Price	Fair Value Asset/(Liability)[2]	Option Type
	(barrels)	(gallons)	(per barrel)	(in thousands)	
2007	1,275,000	78,681,000	$ 60.00	$ 782	Puts purchased
2007	1,275,000	78,681,000	75.18	(2,543)	Calls sold
2008	4,269,600	260,692,000	60.00	12,546	Puts purchased
2008	4,269,600	260,692,000	79.20	(17,100)	Calls sold

2009	4,752,000	290,364,000	60.00		19,667	Puts purchased
2009	4,752,000	290,364,000	78.68		(25,638)	Calls sold
2010	2,413,500	149,009,000	60.00		11,104	Puts purchased
2010	2,413,500	149,009,000	77.28		(14,296)	Calls sold
				$	(15,478)	

Natural Gas Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu) (3)	Fair Value Liability(2) (in thousands)
2007	540,000	$ 7.255	$ (40)
2008	240,000	7.270	(266)
2009	480,000	8.000	(265)
			$ (571)

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Asset/(Liability)(2) (in thousands)
2007	2,820,000	$ (0.771)	$ (157)
2008	4,440,000	(0.671)	(294)
2009	4,920,000	(0.558)	(215)
2010	2,220,000	(0.575)	33
			$ (633)

Natural Gas Purchases

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Liability(2) (in thousands)
2007	5,460,000	$ 8.593(4)	$ (8,582)
2008	11,016,000	8.951(5)	(6,626)
2009	10,320,000	8.687	(1,390)
2010	4,380,000	8.635	(515)
			$ (17,113)

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(3)	Average Fixed Price (per mmbtu)(3)	Fair Value Liability(2) (in thousands)
2007	7,740,000	$ (1.036)	$ (73)
2008	15,216,000	(1.125)	(599)
2009	14,760,000	(0.659)	(1,299)
2010	6,600,000	(0.560)	(1,188)

			$ (3,159)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability[2] (in thousands)
2007	37,700	$ 56.249	$ (561)
2008	65,400	59.424	(842)
2009	33,000	62.700	(321)
			$ (1,724)

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Asset/(Liability)[2] (in thousands)	Option Type
2007	324,600	60.000	223	Puts purchased
2007	324,600	75.256	(656)	Calls sold
2008	691,800	60.000	1,804	Puts purchased

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Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)		Fair Value Asset/(Liability)[2] (in thousands)	Option Type
2008	691,800	78.004		(3,025)	Calls sold
2009	738,000	60.000		3,045	Puts purchased
2009	738,000	80.622		(3,549)	Calls sold
2010	402,000	60.000		1,753	Puts purchased
2010	402,000	79.341		(1,947)	Calls sold
2011	30,000	60.000		164	Puts purchased
2011	30,000	74.500		(223)	Calls sold
2012	30,000	60.000		177	Puts purchased
2012	30,000	73.900		(237)	Calls sold
			$	(2,471)	
		Total net liability	$	(58,375)	

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

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

(3)

Mmbtu represents million British Thermal Units.

(4) Includes our premium received from our sale of an option for us to sell 2,400,000 mmbtu of natural gas at an average price of $15.00 per mmbtu for the year ended December 31, 2007.

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

ITEM 4. CONTROLS AND PROCEDURES

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

Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective at the reasonable assurance level.

As of December 31, 2006, management concluded that our internal control over financial reporting was ineffective, based on our evaluation under the COSO framework, because it identified a material weakness with regard to our accounting for certain derivative instruments in accordance with Statement of Financial Accounting Standards

No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Specifically, we entered into a significant number of option instruments (a combination of puts purchased and calls sold that are commonly known as costless collars) in September 2006 to hedge our exposure to movements in commodity prices that were not appropriately valued within our consolidated financial statements under the provisions of SFAS No. 133. While the costless collars were valued appropriately with regard to their intrinsic value, we did not record a fair value for the time-value component of the derivative instruments. All of our other derivative instruments that were in effect during 2006 had been appropriately recorded within our consolidated financial statements as of December 31, 2006. This material weakness resulted in the amendment of our Form 10-Q as of September 30, 2006.

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

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

Exhibit No.	Description
2.1	Master Formation Agreement by and between the Partnership and Western Gas Resources, Inc. to form Atlas Pipeline Mid-Continent WestTex, LLC(1)
2.2	Master Formation Agreement by and among the Partnership, Western Gas Resources, Inc. and Western Gas Resources Westana, Inc. to form Atlas Pipeline Mid-Continent WestOk, LLC(1)
3.1	Second Amended and Restated Agreement of Limited Partnership (2)
3.1a	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership
3.2	Certificate of Limited Partnership of Atlas Pipeline Partners, L.P. (3)
3.3a	Certificate of Designation of 6.5% Cumulative Convertible Preferred Units (4)
3.3b	Amended and Restated Certificate of Designation of 6.5% Cumulative Convertible Preferred Units(5)
10.1	Securities Purchase Agreement dated as of April 18, 2007 among the Partnership, Atlas Pipeline Finance Corp. and Sunlight Capital Partners, LLC(5)
10.2	Registration Rights Agreement dated as of April 18, 2007 among the Partnership, Atlas Pipeline Finance Corp. and Sunlight Capital Partners, LLC(5)
10.3	Common Unit Purchase Agreement by and among Atlas Pipeline Partners, L.P. and the purchasers named therein(1)
10.4	$900.0 million Senior Unsecured Term Loan Facility and $250.0 Senior Secured Revolving Credit Facility Commitment Letter dated June 1, 2007 among the Partnership, Wachovia Bank, National Association and Wachovia Capital Markets, LLC(1)
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 current report on Form 8-K, filed on June 5, 2007 and incorporated herein by reference.

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

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

(4) 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.

(5) Previously filed as an exhibit to the Partnership s current report on Form 8-K, filed

on April 19, 2007 and incorporated herein by reference.

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: August 8, 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: August 8, 2007	By: /s/ MICHAEL L.STAINES
	Michael L. Staines President, Chief Operating Officer and Managing Board Member of the General Partner
Date: August 8, 2007	By: /s/ MATTHEW A. JONES
	Matthew A. Jones Chief Financial Officer of the General Partner
Date: August 8, 2007	By: /s/ SEAN P. MCGRATH
	Sean P. McGrath Chief Accounting Officer of the General Partner