ATLAS PIPELINE PARTNERS LP
Form 10-Q
November 08, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2004

OR

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

For the transition period from _________ to _________

Commission file number: **1-4998**

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes [X] No [ ]

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, except unit data)

	September 30, 2004	December 31, 2003
	(Unaudited)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 29,020	$ 15,078
Accounts receivable	11,341	12
Prepaid expenses	808	67
Total current assets	41,169	15,157
Property, plant and equipment, net	172,312	29,628
Goodwill (net of accumulated amortization of $285)	2,305	2,305
Other long-term assets	4,472	2,422
	$ 220,258	$ 49,512
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 3,062	$ --
Accounts payable and accrued liabilities	16,313	521
Accounts payable - affiliates	6,189	1,673
Distribution payable	6,030	3,073
Total current liabilities	31,594	5,267
Other long-term liabilities	2,060	--
Long-term debt, less current portion	57,158	--
Partners' capital (deficit):		
Common unitholders, 5,563,659 and 2,713,659 units outstanding	132,224	43,551
Subordinated unitholder, 1,641,026 units outstanding	(1,040)	354
General partner	2,190	340
Accumulated other comprehensive loss	(3,928)	--
Total partners' capital	129,446	44,245
	$ 220,258	$ 49,512

See accompanying notes to consolidated financial statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
Revenues:				
Natural gas and liquids	$30,048	$ --	$30,048	$ --
Transportation and compression	4,665	4,163	13,344	11,816
Interest income and other	166	36	282	61
Total revenues	34,879	4,199	43,674	11,877
Costs and expenses:				
Natural gas and liquids	24,588	--	24,588	--
Plant operating	931	--	931	--
Transportation and compression	564	607	1,709	1,831
General and administrative	1,737	435	2,901	1,301
Depreciation and amortization	1,022	438	2,132	1,266
Interest expense	1,075	50	1,202	212
Terminated acquisition	2,987	--	2,987	--
Total costs and expenses	32,904	1,530	36,450	4,610
Net income	$ 1,975	$2,669	$ 7,224	$ 7,267
Net income - limited partners	$ 1,016	$2,352	$ 5,497	$ 6,611
Net income - general partner	$ 959	$ 317	$ 1,727	$ 656
Basic net income per limited partner unit	$ .15	$ .54	$ 1.01	$ 1.72
Weighted average limited partner units outstanding - basic	6,839	4,355	5,416	3,854
Diluted net income per limited partner unit	$ .15	$ .54	$ 1.01	$ 1.72
Weighted average limited partner units - diluted	6,898	4,355	5,441	3,854

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2004
(Unaudited)
(in thousands, except unit data)

	Number of Limited Partner Units					Accumulatd Other Comprehensive Loss	Total Partners' Capital (Deficit)
	Common	Subordinated	Common	Subordinated	General Partner		
Balance at January 1, 2004	2,713,659	1,641,026	$ 43,551	$ 354	$ 340	$ --	$ 44,245
Issuance of common units, net of offering costs	2,850,000	--	92,714	--	--	--	92,714
Capital contribution	--	--	--	--	1,994	--	1,994
Distribution to partners	--	--	(3,893)	(2,068)	(812)	--	(6,773)
Distribution payable	--	--	(3,839)	(1,132)	(1,059)	--	(6,030)
Other comprehensive loss	--	--	--	--	--	(3,928)	(3,928)
Net income	--	--	3,692	1,806	1,727	--	7,224
Balance at September 30, 2004	5,563,659	1,641,026	$ 132,224	$ (1,040)	$ 2,190	$ (3,928)	$ 129,446

See accompanying notes to consolidated financial statements

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

	September 30, 2004	**September 30, 2003**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 7,224	$ 7,267
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	2,132	1,266
Non-cash loss on derivative value	585	--
Non-cash compensation on long-term incentive plan	342	--
Alaska Pipeline Company acquisition costs	2,987	--
Loss on disposal of fixed assets	7	--
Amortization of deferred finance costs	219	86
Changes in operating assets and liabilities:		
Changes in operating assets and liabilities	499	2,846
Increase in accounts payable - affiliates	3,741	--
Net cash provided by operating activities	17,736	11,465
CASH FLOWS FROM INVESTING ACTIVITIES:		
Business acquisition, net of cash acquired	(141,564)	--
Capital expenditures	(4,419)	(4,143)
(Increase) decrease in other assets	67	(868)
Proceeds from disposal of fixed assets	188	--
Net cash used in investing activities	(145,728)	(5,011)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings on credit facilities	100,000	2,000
Repayments of credit facilities	(40,000)	(8,500)
Repayments on other long-term debt	(13)	--
Capital contributions	1,994	539
Issuance of common units, net of offering costs	92,714	25,182
Distributions paid to partners	(9,846)	(6,572)
Increase in other assets	(2,915)	(864)
Net cash provided by financing activities	141,934	11,785
Increase in cash and cash equivalents	13,942	18,239
Cash and cash equivalents, beginning of period	15,078	1,859
Cash and cash equivalents, end of period	$ 29,020	$ 20,098

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2004
(Unaudited)

NOTE 1 BASIS OF PRESENTATION

The consolidated financial statements of Atlas Pipeline Partners, L.P. (the Partnership) and its wholly-owned subsidiaries as of September 30, 2004 and for the three and nine month periods ended September 30, 2004 and 2003 are unaudited. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted in this Form 10-Q pursuant to the rules and regulations of the Securities and Exchange Commission. However, in the opinion of management, these interim financial statements include all the necessary adjustments to fairly present the results of the interim periods presented. The unaudited interim consolidated financial statements should be read in conjunction with the audited financial statements included in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2003. The results of operations for the nine month period ended September 30, 2004 may not necessarily be indicative of the results of operations for the full year ending December 31, 2004.

Certain reclassifications have been made to the consolidated financial statements for the three and nine month periods ended September 30, 2003 to conform to the presentation for the three and nine month periods ended September 30, 2004.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further in this note, the Partnership s significant accounting policies are detailed in its audited consolidated financial statements and notes thereto in the Partnership s annual report on Form 10-K for the year ended December 31, 2003 filed with the Securities and Exchange Commission.

Net Income Per Unit

Net income per limited partner unit is based on the weighted average number of common and subordinated units outstanding during the period. Basic net income per limited partner unit is computed by dividing net income, after deducting the general partner s 2% and incentive distributions, by the weighted average number of outstanding common units and subordinated units. Diluted net income per limited partner unit is computed by dividing net income attributable to limited partners by the sum of the weighted average number of common and subordinated units outstanding and the weighted average number of phantom units during the period. Phantom units consist of common units issuable under the terms of the Partnership s Long-Term Incentive Plan (see Note 7).

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Net Income Per Unit (Continued)

The following table presents a reconciliation of the components used in the computation of net income per limited partner unit-basic and net income per limited partner unit-diluted for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands)		(in thousands)	
Net income - limited partners	$ 1,016	$ 2,352	$ 5,497	$ 6,611
Weighted average limited partner units outstanding - basic	6,839	4,355	5,416	3,854
Dilutive effect of phantom units	59	--	25	--
Weighted average limited partner units - diluted	6,898	4,355	5,441	3,854

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income, are referred to as other comprehensive income (loss) and for the Partnership include only changes in the fair value of unrealized hedging gains and losses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands)		(in thousands)	
Net income	$ 1,975	$ 2,669	$ 7,224	$ 7,267
Other comprehensive loss:				
Unrealized loss on hedging contracts	(3,955)	--	(3,955)	--
Less: reclassification adjustment for losses realized in net income	27	--	27	--
	(3,928)	--	(3,928)	--
Comprehensive (loss) income	$ (1,953)	$ 2,669	$ 3,296	$ 7,267

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Cash Flow Statements

The Partnership considers temporary investments with a maturity at the date of acquisition of 90 days or less to be cash equivalents. Supplemental disclosure of cash flow information:

	Nine Months Ended September 30,	
	2004	2003
	(in thousands)	
Cash paid during the period for:		
Interest	$ 757	$ 127
Non-cash activities include the following:		
Fair value of assets acquired	$ 161,603	$ --
Liabilities assumed	(19,235)	--
Net cash paid	$ 142,368	$ --

Goodwill

Goodwill is evaluated for impairment in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwilld and Other Intangible Assets." As of January 1, 2002, the date of adoption, the Partnership had unamortized goodwill in the amount of $2.3 million. The Partnership evaluates its goodwill at least annually and will reflect the impairment of goodwill, if any, in operating income in the income statement in the period in which the impairment is indicated.

Property, Plant and Equipment

A summary of property, plant and equipment at the dates indicated is as follows:

	September 30, 2004	December 31, 2003
	(in thousands)	
Pipelines and compression facilities	$ 162,824	$ 36,390
Rights of way	14,703	623
Buildings and improvements	3,158	--
Furniture and equipment	478	--
Other	650	5
	181,813	37,018
Less - accumulated depreciation	(9,501)	(7,390)
	$ 172,312	$ 29,628

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Assets

Other assets include deferred finance costs which are recorded at cost and amortized over the term of the associated debt. The following is a summary of the Partnership s other assets at the dates indicated:

	September 30, 2004	December 31, 2003
	(in thousands)	
Deferred finance costs, net of accumulated amortization of $325 and $106	$ 3,461	$ 767
Security deposits	987	--
Alaska Pipeline Company acquisition costs (see Note 10)	--	1,579
Other	24	76
	$ 4,472	$ 2,422

Fair Value of Financial Instruments

The Partnership uses the following methods and assumptions in estimating the fair value of each class of financial instruments for which it is practicable to estimate fair value.

For cash and cash equivalents, receivables and payables, the carrying amounts approximate fair value because of the short maturity of these instruments.

For hedging agreements, the fair values are based on fixed price positions compared to New York Mercantile Exchange, Inc. (NYMEX) forward prices.

For the credit facilities, the carrying value approximates fair value because the floating rate debt bears interest at rates generally set for periods of three months or less.

Derivative Instruments

The Partnership applies the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," ("SFAS 133"). SFAS 133 requires each derivative instrument to be recorded in the balance sheet as either an asset or liability measured at fair value. Changes in a derivative s instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met.

Revenue and Cost Recognition

Revenues and costs for natural gas and liquids are recognized at the time the natural gas is processed and the natural gas and natural gas liquids are delivered to market.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 3 SPECTRUM ACQUISITION

On July 16, 2004, the Partnership acquired Spectrum Field Services, Inc. (Spectrum or Mid Continent), also referred to as Mid-Continent, for approximately $142.4 million, including transaction costs and the payment of taxes due as a result of the transaction. Spectrum s principal assets include 1,900 miles of natural gas pipelines and a natural gas processing facility in Velma, Oklahoma.

In connection with the acquisition of Spectrum, the Partnership entered into commitment agreements with Resource America, Inc. (Resource America) and Atlas America, Inc. (Atlas America) for the purchase of up to $25.0 million of preferred units in Atlas Pipeline Operating Partnership, L.P., the Partnership s subsidiary. In consideration for their commitments, upon the closing of the Spectrum acquisition and the purchase by each of $10.0 million preferred units, the Partnership paid Resource America and Atlas America commitment fees of $750,000 and $500,000, respectively.

In April and July 2004, the Partnership completed public offerings of 750,000 and 2,100,000 common units, respectively. The net proceeds after underwriting discounts, commissions and costs were $25.2 million and $67.5 million, respectively. The General Partner simultaneously contributed $535,000 and $1.5 million to the Partnership in order to maintain its 2% general partner interest in the Partnership.

The Partnership financed the Spectrum acquisition, including approximately $4.2 million of transaction costs, as follows:

- borrowing $100.0 million under the term loan portion of its $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank, National Association (Note 9);
- using the $20.0 million of proceeds received from the sale to Resource America and Atlas America of preferred units in Atlas Pipeline Operating Partnership; and
- using $22.4 million of net proceeds from the Partnership's April 2004 common unit offering.

On July 20, 2004, the Partnership used a portion of the July 2004 public offering to repay $40.0 million of the borrowings under its $135.0 million credit facility and to repurchase the preferred units from Resource America and Atlas America for $20.4 million.

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

The Partnership is also a party to various routine legal proceedings arising out of the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or operations.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 3 SPECTRUM ACQUISITION (Continued)

The acquisition was accounted for using the purchase method of accounting under SFAS No. 141, "Business Combination." The following table presents the allocation of the acquisition cost, including professional fees and other related acquisition costs to the assets acquired and liabilities assumed, based on their fair values at the date of acquisition (in thousands):

Cash and cash equivalents	$ 804
Accounts receivable	18,504
Prepaid expenses	649
Property, plant and equipment	140,592
Other long-term assets	1,054
Total assets acquired	161,603
Accounts payable and accrued liabilities	(17,552)
Hedging liabilities	(1,519)
Long-term debt	(164)
Total liabilities assumed	(19,235)
Net assets acquired	$ 142,368

The Partnership is in the process of evaluating certain estimates made in the purchase price and related allocations; thus, the purchase price and allocation are both subject to adjustment.

The results of operations of Spectrum are included in the Partnership's consolidated statements of operations from July 16, 2004, the date of the acquisition.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 3 SPECTRUM ACQUISITION (Continued)

The following summarized pro forma consolidated income statement information for the three and nine months ended September 30, 2004 and 2003, assumes that the acquisition discussed above occurred as of January 1, 2003. The Partnership has prepared these pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if the Partnership had completed this acquisition as of the periods shown below or the results that will be attained in the future. The amounts presented below are in thousands, except per unit amounts:

	Three Months Ended September 30, 2004			Three Months Ended September 30, 2003		
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$ 34,879	$ 5,988	$ 40,867	$ 4,199	$ 22,477	$ 26,676
Net income	$ 1,975	$ (245)	$ 1,730	$ 2,669	$ (35)	$ 2,634
Basic net income per limited partner unit	$ .15	$ (.04)	$ .11	$ .54	$ (.24)	$ .30
Diluted net income per limited partner unit	$ .15	$ (.04)	$ .11	$ .54	$ (.24)	$ .30
Weighted average number of limited partner units used for basic net income per unit calculation	6,839	366	7,205	4,355	2,850	7,205
Weighted average number of limited partner units used for diluted net income per unit calculation	6,898	366	7,263	4,355	2,850	7,205

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 3 SPECTRUM ACQUISITION (Continued)

	Nine Months Ended September 30, 2004			Nine Months Ended September 30, 2003		
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported	Pro Forma Adjustments	Pro Forma
Revenues	$ 43,674	$ 67,643	$ 111,317	$ 11,877	$ 76,516	$ 88,393
Net income	$ 7,224	$ 4,501	$ 11,725	$ 7,267	$ 2,604	$ 9,871
Basic net income per limited partner unit	$ 1.01	$ .31	$ 1.32	$ 1.72	$ (.43)	$ 1.29
Diluted net income per limited partner unit	$ 1.01	$ .31	$ 1.32	$ 1.72	$ (.43)	$ 1.29
Weighted average number of limited partner units used for basic net income per unit calculation	5,416	1,789	7,205	3,854	2,952	6,806
Weighted average number of limited partner units used for diluted net income per unit calculation	5,441	1,789	7,230	3,854	2,952	6,806

Significant pro forma adjustments includes, revenues and costs and expenses for the period prior to the Partnerships acquisition, interest and depreciation expenses and the elimination of income taxes.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 4 DERIVATIVE INSTRUMENTS

The Partnership entered into certain financial swap instruments, some of which settled during the three months ended September 30, 2004 that are designated as cash flow hedging instruments in accordance with SFAS 133. The maturities of the instruments outstanding at September 30, 2004, are less than three years. The swap instruments are contractual agreements to exchange obligations of money between the buyer and seller of the instruments as natural gas, natural gas liquid and crude oil volumes during the pricing period are sold. The swaps are tied to a set fixed price for the seller and floating price determinants for the buyer priced on certain indices at the end of the relevant trading period. Options have also been entered that fix the price for the seller within the puts purchased and calls sold and floating price determinants for the buyer priced on certain indices at the end of the relevant trading period. The Partnership entered into these instruments to hedge the forecasted gas plant residue, natural gas liquid and crude sales to variability in expected future cash flows attributable to changes in market prices. For the instruments that were settled during the three months ended September 30, 2004, the Partnership recognized a loss of $27,000.

The Partnership entered into several swaps that were designed to hedge natural gas liquid prices during the three months ended September 30, 2004 that did not meet specific hedge accounting criteria. The Partnership recognized a loss of $697,000 related to these instruments during the three months ended September 30, 2004.

As of September 30, 2004, the Partnership had the following natural gas liquids, natural gas, and crude oil volumes hedged.

Natural Gas Liquids Fixed-Price Swaps

Production Period	Volumes (Gallons)	Average Fixed Price	Fair Value Liability
		(per gallon)	(in thousand)
2004	2,562,000	$ 0.645	$ (282)
2005	10,584,000	0.537	(2,524)
2006	6,804,000	0.575	(1,030)
			$ (3,836)

Natural Gas Fixed Price Swaps

Production Period	Volumes (MMBTU)[1]	Average Fixed Price	Fair Value Liability
		(per MMBTU)	(in thousand)
2005	960,000	$ 6.165	$ (697)
2006	450,000	5.920	(160)
			$ (857)

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 4 DERIVATIVE INSTRUMENTS (Continued)

Natural Gas Options

Production Period	Option Type	Volumes (MMBTU)[1]	Average Strike Price	Fair Value Asset (Liability)
			(per MMBTU)	(in thousand)
2004	Puts purchased	150,000	$ 5.700	$ 7
2004	Calls sold	150,000	6.97	(41)
2005	Puts purchased	180,000	5.875	--
2005	Calls sold	180,000	7.110	(145)
				$ (179)

Crude Fixed price Swaps

Production Period	Volumes (Barrels)	Average Fixed Price	Fair Value Liability (in thousands)
			(in thousand)
2006	18,000	$ 38.767	$ (31)

Crude Options

Production Period	Option Type	Volumes (Barrels)	Average Strike Price	Fair Value Asset / (Liability)
			(per barrel)	(in thousands)
2004	Puts purchased	25,000	$ 32.200	$ --
2004	Calls sold	25,000	38.560	(244)
2005	Puts purchased	75,000	30.067	--
2005	Calls sold	75,000	34.383	(846)
2006	Puts purchased	5,000	30.000	--
2006	Calls sold	5,000	34.250	(39)
				$ (179)

(1) MMBTU means Million British Thermal Units.

As of September 30, 2004, the fair value of the swap agreements the Partnership had entered into in order to convert the Partnership s market-sensitive floating price contracts to fixed-price positions resulted in a $6.0 million liability.

NOTE 5 DISTRIBUTION DECLARED

The Partnership makes quarterly cash distributions of its available cash, generally defined as cash on hand at the end of the quarter less cash reserves deemed appropriate to provide for future operating costs, potential acquisitions and future distributions.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 5 DISTRIBUTION DECLARED (Continued)

On September 20, 2004, the Partnership declared a cash distribution of $.69 per unit on its outstanding common units and subordinated units. The distribution represents the available cash flow less cash reserves for the three months ended September 30, 2004. The $6,030,000 distribution, which includes a distribution of $1,059,000 to the general partner, will be paid on November 5, 2004 to unitholders of record on September 30, 2004.

Available cash is initially distributed 98% to limited partners and 2% to the general partner. These distribution percentages are modified to provide for incentive distributions to be paid to the general partner in the event that quarterly distributions to unitholders exceed certain specified targets. Incentive distributions are generally defined as all cash distributions paid to the general partner that are in excess of 2% of the aggregate amount of cash being distributed. The general partner s incentive distributions for the distributions declared for the three and nine months ended September 30, 2004 were $938,600 and $1,614,800, respectively, and for the three and nine months ended September 30, 2003 were $268,600 and $519,400, respectively.

NOTE 6 SPECIAL MEETING OF UNITHOLDERS

On February 11, 2004, at a special meeting of unitholders, the following were approved:

- o The issuance of up to 2.0 million common units in connection with the Partnership s proposed acquisition of Alaska Pipeline Company, of which 750,000 common units were issued in April 2004. (see Note 10)

- o The Atlas Pipeline Partners, L.P. Long-Term Incentive Plan (the Plan) in which officers, employees and non-employee managing board members of Atlas Pipeline Partners GP, LLC (the General Partner) and employees of the General Partner s affiliates, consultants and joint venture partners who perform services for the Partnership are eligible to participate. The Plan is administered by a committee appointed by the General Partner s managing board (the Committee), which sets the terms of awards under the Plan. The Committee may make awards of either phantom units or options for an aggregate of 435,000 common units, provided that the maximum number of phantom units that may be awarded in total to non-employee managing board members is 10,000. A phantom unit entitles the grantee to receive a common unit upon the 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 the right, known as a DER, 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. An option entitles the grantee to purchase the Partnership s common units at an exercise price determined by the Committee, which may be less than, equal to or more than the fair market value of the Partnership s common units on the date of the grant. The Committee also has discretion to determine how the exercise price may be paid. 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. Phantom units awarded to non-employee managing board members will vest over a 4-year period at the rate of 25% per year. Both types of awards will automatically vest upon a change of control, as defined in the Plan.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 6 SPECIAL MEETING OF UNITHOLDERS (Continued)

After the special meeting of unitholders was adjourned and reconvened on March 9, 2004, the unitholders approved amendments to the partnership agreement that remove the limitations on the Partnership s ability to issue common units and incur debt.

NOTE 7 LONG-TERM INCENTIVE PLAN

The Partnership has a Long-Term Incentive Plan as discussed in Note 6. During the nine months ended September 30, 2004, 59,598 phantom units were granted. Grants for 846 units were forfeited during the three months ended June 30, 2004, leaving 58,752 phantom units outstanding as of September 30, 2004. The Partnership recognized $346,700 and $419,000 in compensation expense related to these grants and their associated distributions in the three months and nine months ended September 30, 2004. The fair market value associated with these grants was $2.2 million which is amortized into expense over the vesting period of the units.

A summary of the fair market value of equity-based incentive compensation awards of phantom units for the three and nine months ended September 30, 2004 and 2003 is listed below. To date, no unit options have been awarded under the Plan.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(in thousands, except per unit data)			
2004 incentive compensation awards	$ 37	$ --	$ 2,213	$ --
2004 forfeitures	--	--	30	--
Total outstanding awards	$ 37	$ --	$ 2,183	$ --
Weighted average fair-value of phantom unit granted	$ 36.60	$ --	$ 37.16	$ --

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 8 OPERATING SEGMENT INFORMATION AND MAJOR CUSTOMERS

The Partnership s operations include two reportable operating segments. In addition to the reportable operating segments, certain other activities are reported in the Other category. These operating segments reflect the way the Partnership manages its operations and makes business decisions.

Operating segment data for the periods indicated are as follows:

Three Months Ended September 30, 2004 (in thousands):

	Mid-Continent	Appalachia	Other (a)	Total
Revenues from external customers	$ 30,048	$ 4,665	$ --	$ 34,713
Interest income	--	--	120	120
Interest expense	3	--	1,072	1,075
Depreciation and amortization	613	409	--	1,022
Segment profit (loss)	3,558	3,693	(5,276)	1,975
Other significant items:				
Segment assets	154,741	36,496	29,021	220,258

Three Months Ended September 30, 2003 (in thousands):

	Mid-Continent	Appalachia	Other (a)	Total
Revenues from external customers	$ --	$ 4,163	$ --	$ 4,163
Interest income	--	--	36	36
Interest expense	--	--	50	50
Depreciation and amortization	--	438	--	438
Segment profit (loss)	--	3,118	(449)	2,669
Other significant items:				
Segment assets	--	30,735	20,097	50,832

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 8 OPERATING SEGMENT INFORMATION AND MAJOR CUSTOMERS (Continued)

Nine Months Ended September 30, 2004 (in thousands):

	Mid-Continent	Appalachia	Other (a)	Total
Revenues from external customers	$ 30,048	$ 13,344	$ --	$ 43,392
Interest income	--	--	204	204
Interest expense	3	--	1,199	1,202
Depreciation and amortization	613	1,519	--	2,132
Segment profit (loss)	3,558	10,116	(6,450)	7,224
Other significant items:				
Segment assets	154,741	36,496	29,021	220,258

Nine Months Ended September 30, 2003 (in thousands):

	Mid-Continent	Appalachia	Other (a)	Total
Revenues from external customers	$ --	$ 11,816	$ --	$ 11,816
Interest income	--	--	61	61
Interest expense	--	--	212	212
Depreciation and amortization	--	1,266	--	1,266
Segment profit (loss)	--	8719	(1,452)	7,267
Other significant items:				
Segment assets	--	30,735	20,097	50,832

(a) Other includes non-allocable interest and general and administrative expenses.

Segment profit (loss) represents total revenues less costs and expenses attributable thereto, including interest and depreciation and amortization.

The Partnership sells natural gas and natural gas liquids under contract to various purchasers in the normal course of business. For the three month period ended September 30, 2004 Mid-Continent had two purchasers that accounted for approximately 52% of the Partnership s revenues.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 9 CREDIT FACILITY

On July 16, 2004 the Partnership entered into a new $135.0 million credit facility which replaced its existing $20.0 million facility. The loan arrangement, for which Wachovia Bank, National Association serves as administrative agent, includes eleven additional lenders. The facility is comprised of a five-year $60.0 million term loan and a four-year $75.0 million revolving line of credit which can be increased by an additional $40.0 million under certain circumstances. On July 20, 2004, the Partnership repaid $40.0 million of the $100.00 million it had borrowed under the term loan in connection with its acquisition of Spectrum from the proceeds of its July 2004 common unit offering. In August 2004, the lenders agreed to increase the amount available under the revolving credit portion of the facility to $75.0 million.Up to $5.0 million of the facility may be used for standby letters of credit. Borrowings under the facility are secured by a lien on and security interest in all of the Partnership s property and that of the Partnership s subsidiaries and by the guaranty of each of the Partnership s subsidiaries. The credit facility bears interest at one of two rates, elected at the Partnership s option:

- o the base rate plus the applicable margin; or
- o the adjusted London Interbank Offered Rate, or LIBOR, plus the applicable margin.

The base rate for any day equals the higher of the federal funds rate plus 1/2 of 1% or the Wachovia Bank prime rate. Adjusted LIBOR is LIBOR divided by 1.00 minus the percentage prescribed by the Board of Governors of the Federal Reserve System for determining the reserve requirement for euro currency funding. The applicable margin for the revolving line of credit is as follows:

- o where the Partnership's leverage ratio, that is, the ratio of its debt to its earnings before interest, taxes, depreciation and amortization, ("EBITDA"), is less than or equal to 2.5, the applicable margin is 1.00% for base rate loans and 2.0% for LIBOR loans;
- o where the Partnership's leverage ratio is greater than 2.5 but less than or equal to 3.0, the applicable margin is 1.25% for base rate loans and 2.25% for LIBOR loans;
- o where the Partnership's leverage ratio is greater than 3.0 but less than or equal to 3.5, the applicable margin is 1.75% for base rate loans and 2.75% for LIBOR loans; and
- o where the Partnership's leverage ratio is greater than 3.5, the applicable margin is 2.25% for base rate loans and 3.25% for LIBOR loans.

The applicable margin for the term loan is .75% higher for both base rate loans and LIBOR loans. The rates applicable on the Partnership s term loan range from 5.7% to 7.5% at September 30, 2004.

The credit facility requires the Partnership to maintain a ratio of funded debt to EBITDA of not more than 4.25 to 1.0, reducing to 4.0 to 1.0 on December 31, 2004 and 3.5 to 1.0 on September 30, 2005 and an interest coverage ratio of not less than 3.0 to 1.0. In addition, the Partnership must prepay the term loan with the net proceeds of any asset sale or issuance of debt. With respect to any issuances of equity, the Partnership must repay the term loan from the proceeds of such issuances to the extent its ratio of funded debt to EBITDA exceeds 3.5 to 1.0. The Partnership must pay down $750,000 in principal on the outstanding balance of the term loan quarterly, any prepayments of principal with proceeds from asset or equity sales will be credited pro rata against this repayment obligation.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
SEPTEMBER 30, 2004
(Unaudited)

NOTE 9 CREDIT FACILITY (Continued)

The credit agreement contains covenants customary for loans of this size, including restrictions on incurring additional debt and making material acquisitions and a prohibition on paying distributions to our unitholders if an event of default occurs. The events which constitute an event of default are also customary for loans of this size, including payment defaults, breaches of the Partnership s representations or covenants contained in the credit agreement, adverse judgments against it in excess of a specified amount, and a change of control of its general partner.

Annual debt principal payments over the next five fiscal periods ending September 30 are as follows: 2005 $3.1 million; 2006 $3.1 million; 2007 $3.1 million; 2008 $3.0 million; 2009 $47.9 million.

NOTE 10 TERMINATED ALASKA PIPELINE ACQUISITION

In September 2003, the Partnership entered into an agreement with SEMCO Energy, Inc. to purchase all of the stock of Alaska Pipeline Company. In order to complete the acquisition, the Partnership needed the approval of the Regulatory Commission of Alaska. The Regulatory Commission initially approved the transaction, but on June 4, 2004 it vacated its order of approval based upon a motion for clarification or reconsideration filed by SEMCO. On July 1, 2004, SEMCO sent the Partnership a notice purporting to terminate the transaction. The Partnership believes SEMCO caused the delay in closing the transaction and breached its obligations under the acquisition agreement. The Partnership is currently pursuing its remedies under the acquisition agreement. In connection with the acquisition subsequent termination and current legal action, the Partnership incurred $3.0 million of costs, which are shown as terminated acquisition costs on the Partnership s income statement.

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 1, under the caption Risk Factors, in our annual report on Form 10-K for 2003 and in our prospectus supplement dated July 14, 2004. These risks and uncertainties could cause actual results to differ materially. 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 operation. This discussion should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this report.

General

Our principal business objective is to generate income for distribution to our unitholders.

Our business is conducted in the midstream natural gas industry and we are active in the Appalachian and Mid-Continent areas of the United States, specifically Pennsylvania, Ohio, New York, Oklahoma and Texas.

In Appalachia, we gather approximately 54 million cubic feet of gas per day through our pipeline system from more than 5,200 wells for delivery to a variety of customers on major intra or inter state pipeline systems and a limited number of direct end-users.

This transported gas is primarily controlled by Atlas America, Inc., the parent company of our general partner.

Our Mid-Continent operations began in July 2004 upon our acquisition of Spectrum Field Services, Inc. In the Mid-Continent, we purchase approximately 55 million cubic feet of gas per day under more than 650 separate gas purchase contracts. This gas is then transported to our Velma, Oklahoma gas processing facility where the natural gas liquids or NGLs, along with various impurities are removed. The remaining pipeline quality gas is then delivered into a major intra state pipeline system where it is sold at market prices. The NGLs are similarly delivered into a separate major intrastate pipeline system where they are also sold for a price determined by the value of the actual components of that liquid stream, for example, ethane, butane, propane etc.

Fee Arrangements

The fees we earn fall into the following two types:

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

Percent of Proceeds or POP Contracts: These contracts provide for us to retain a negotiated percentage of the residue natural gas and NGLs resulting from our gathering and processing operations 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 ultimate market value.

Unlike many of our competitors, we have no keep-whole contracts where the producer has the right to receive 100% of the thermal value of its produced raw natural gas based on the value of the processed and delivered pipeline quality residue natural gas. This type of contract exposes the processing company to frac-spread risk the difference between the value of the NGL extracted from processing and the thermal value equivalent of the residue natural gas.

In Appalachia, substantially all of the gas we transport is for Atlas America, Inc under a POP contract where we earn a fee equal to 16% of the selling price of the gas subject, in most cases to a minimum of $.35 or $.40 per thousand cubic feet or mcf in varying situations. Since our inception in January 2000, our transportation fee has always exceeded this minimum. The balance of the Appalachian gas we transport is for third party operators generally under fee contracts.

In the Mid-Continent, approximately 78% of our volumes and revenues are derived from POP contracts. The percentage of the proceeds that we retain is negotiated and can vary greatly depending on a variety of factors and circumstances.

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. 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. The number of active oil and gas rigs has increased in the past year, mainly due to recent significant increases in natural gas prices which could result in sustained increases in drilling activity during 2004. 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 these 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. The recognition in our Consolidated Statements of Income of the cumulative changes in the fair value of these hedge instruments reduced our results of operations by $724,000 in the three months ended September 30, 2004. See Item 3. Quantitative and Qualitative Disclosure About Market Risk . The remaining term over which we are currently hedging our exposure to the variability of future cash flows is through the end of 2006.

Spectrum Acquisition

On July 16, 2004, we acquired Spectrum Field Services, Inc., which we refer to as Spectrum or Mid-Continent, for approximately $142.4 million, including the payment of taxes due as a result of the transaction. This acquisition significantly increased our size and diversified the natural gas supply basins in which we operate and the natural gas midstream services we provide to our customers. We expect the Spectrum acquisition to be accretive to our cash distributions per common unit.

We financed the Spectrum acquisition, including approximately $4.2 million of transaction costs, as follows:

- o borrowing $100.0 million under the term loan portion of our new $135.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank, National Association;
- o using the $20.0 million of net proceeds received from the sale to Resource America, Inc. and Atlas America, Inc. of preferred units in our operating subsidiary Atlas Pipeline Operating Partnership, L.P.; and
- o using $22.4 million of the net proceeds from our April 2004 common unit offering.

In July 2004, we completed a public offering of 2,100,000 common units of limited partner interest whose net proceeds after underwriting discounts and commissions and costs were $67.5 million We used a portion of the net proceeds of this offering to repay $40.0 million of the borrowings under our new credit facility and to repurchase the preferred units from Resource America and Atlas America.

The acquisition of Spectrum significantly changed our financial position and results of operations At September 30, 2004 we had an available borrowing capacity $72.5 million. We intend to finance our growth with a combination of long-term debt and equity to maintain our financial flexibility to fund future opportunities.

Results of Operations

We set forth the average volumes we transported or delivered, our average rates per mcf and revenues received by us for the periods indicated in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Average daily throughput volumes in mcf (Mid-Continent)	55,056	--	55,056	--
Average daily throughput volumes in mcf (Appalachia)	54,337	54,609	52,745	53,146
Total average daily throughput volumes in mcf	109,393	54,609	107,801	53,146
Average gross margin rate per mcf (Mid-Continent)	$ .78	$ --	$ .78	$ --
Average transporation rate per mcf (Appalachia)	$ .93	$ .83	$ .92	$ .81
Total natural gas and liquids gross margin (Mid-Continent)	$ 5,460	$ --	$ 5,460	$ --
Total transportation revenues (Appalachia)	$ 4,665	$ 4,163	$ 13,344	$ 11,816

Three Months Ended September 30, 2004 Compared to Three Months Ended September 30, 2003

Revenues. Our natural gas and NGL revenues are associated with our acquisition of Spectrum on July 16, 2004. These revenues reflect two and one half months of operations in the current year period and as a result, we expect these revenues will increase in the fourth quarter of 2004.

Our transportation and compression revenues are associated with our Appalachia operations. These revenue increased to $4.7 million in the three months ended September 30, 2004 from $4.2 million in the three months ended September 30, 2003. The increase of $502,000 (12%) resulted from an increase in the average transportation rate paid to us ($526,000) partially offset by a decrease in the volumes of natural gas we transported ($24,000).

Our average daily throughput volumes in Appalachia were 54,337 mcf in the three months ended September 30, 2004 as compared to 54,609 mcf in the three months ended September 30, 2003, a decrease of 272 mcf. During the three months and twelve months ended September 30, 2004, we added 72 and 337 new wells to our system, respectively. Although production volumes have been added from new wells, overall production for the three months ended September 30, 2004 has declined due to the following factors. Of the above well connections, Atlas America drilled and connected 61 wells during the twelve months ended September 30, 2004 in an area of operation that produces predominately oil. In addition, the decrease in the three months ended September 30, 2004 as compared to the prior year period includes a decrease resulting from normal recurring adjustments of estimated accruals.

Our average transportation rate in Appalachia was $.93 per mcf in the three months ended September 30, 2004 as compared to $.83 per mcf in the three months ended September 30, 2003, an increase of $.10 per mcf (12%). In the third quarter of 2004, natural gas prices were higher than those of the prior year period. Since our transportation rates are generally at fixed percentages of the sales price of the natural gas we transport, the higher prices resulted in an increase in our average transportation rate.

Costs and Expenses. Our natural gas and NGLs and plant operating expenses are associated with our acquisition of Spectrum on July 16, 2004. These costs reflect two and one half months of operations in the current year period and as a result, we expect they will increase in the fourth quarter of 2004.

Our transportation and compression expenses in Appalachia decreased to $564,000 in the three months ended September 30, 2004 as compared to $607,000 in the three months ended September 30, 2003, a decrease of $43,000 (7%). Our average cost per mcf for transportation and compression was $.11 in the three months ended September 30, 2004 as compared to $.12 in the three months ended September 30, 2003. This decrease primarily resulted from a decrease in compressor lease payments as a result of our decision to purchase the majority of the compressors we had previously leased.

Our general and administrative expenses increased to $1.7 million in the three months ended September 30, 2004 as compared to $435,000 in the three months ended September 30, 2003, an increase of $1.3 million. This increase includes $484,000 of general and administrative expenses associated with Spectrum which we acquired on July 16, 2004. In addition, allocations of compensation and benefits from Atlas America and its affiliates increased $197,000 during the current year period due to an increase in management time spent on our acquisition and public offering. Additionally, the expensing of phantom units issued under the our Long-Term Incentive Plan and the related distributions on those units increased general and administrative expense by $346,700. In accordance with accounting principles generally accepted in the United States of America, the fair value of phantom units is amortized over the vesting period of these units and the related distributions are recognized in expense as declared. The remainder of the increase for the three months ended September 30, 2004 as compared to the prior year period was the result of higher professional fees primarily associated with the implementation of Sarbannes-Oxley.

Our depreciation and amortization expense increased to $1.0 in the three months ended September 30, 2004 as compared to $438,000 in the three months ended September 30, 2003, an increase of $584,000. This increase resulted from our acquisition of Spectrum. We anticipate that our depreciation will increase in the remainder of 2004.

Our interest expense increased to $1.1 million in the three months ended September 30, 2004 as compared to $50,000 in the three months ended September 30, 2003. This resulted from increased borrowings in the three months ended September 30, 2004 as compared to the same period in 2003. In July 2004, we borrowed $100.0 million to partially fund our acquisition of Spectrum. Subsequently in July 2004, we repaid $40.0 million of these borrowings upon the completion of our public offering. Our interest expense in the three months ended September 30, 2003 consisted of commitment fees on amounts not drawn on our credit facility and amortization of our debt issuance costs.

Our terminated acquisition costs are related to the acquisition of Alaska Pipeline Company, which was purportedly terminated in July 2004. These costs consist primarily of legal and professional fees. In September 2003, we entered into an agreement with SEMCO to purchase all of the stock of Alaska Pipeline Company. In order to complete the acquisition, we needed the approval of the Regulatory Commission of Alaska. The Regulatory Commission initially approved the transaction, but on June 4, 2004 it vacated its order of approval based upon a motion for clarification or reconsideration filed by SEMCO. On July 1, 2004, SEMCO sent us a notice purporting to terminate the transaction. We believe SEMCO caused the delay in closing the transaction and breached its obligations under the acquisition agreement. We are currently pursuing our remedies under the acquisition agreement. In connection with the acquisition, subsequent termination and current legal action, we incurred $3.0 million of costs, which are shown as terminated acquisition costs on our income statement.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Revenues. Our natural gas and NGL revenues are associated with our acquisition of Spectrum on July 16, 2004.

Our transportation and compression revenues increased to $13.3 million in the nine months ended September 30, 2004 from $11.8 million in the nine months ended September 30, 2003. The increase of $1.5 million (13%) resulted from an increase in the average transportation fee paid to us ($1.6 million) partially offset by a decrease in the volumes of natural gas we transported ($52,400).

Our average daily throughput volumes in Appalachia were 52,745 mcf in the nine months ended September 30, 2004 as compared to 53,146 mcf in the nine months ended September 30, 2003, a decrease of 401 mcf (1%). During the nine months and twelve months ended September 30, 2004, we added 264 and 337 new wells to our system, respectively. Although production volumes have been added from new wells, overall production for the nine months ended September 30, 2004 has declined due to the following factors. Of the above well connections, Atlas America drilled and connected 61 wells during the twelve months ended September 30, 2004 in an area of operation that produces predominately oil. The decrease in the nine months ended September 30, 2004 as compared to the prior year period also includes a decrease resulting from normal recurring adjustments of estimated accruals. In addition, in February 2004, a third party producer that had been connected to our Fayette County, Pennsylvania system constructed it own gathering system, resulting in a loss in throughput volumes.

Our average transportation rate in Appalachia was $.92 per mcf in the nine months ended September 30, 2004 as compared to $.81 per mcf in the nine months ended September 30, 2003, an increase of $.11 per mcf (14%). During the nine months ended September 30, 2004, natural gas prices increased over the prior year period. Since our transportation rates are generally at fixed percentages of the sales price of the natural gas we transport, the higher prices resulted in an increase in our average transportation rate.

Costs and Expenses. Our natural gas and liquids and plant operating expenses are associated with our acquisition of Spectrum on July 16, 2004.

Our transportation and compression expenses in Appalachia decreased to $1.7 million in the nine months ended September 30, 2004 as compared to $1.8 million in the nine months ended September 30, 2003, a decrease of $122,000 (7%). Our average cost per mcf for transportation and compression was $.13 in both the nine months ended September 30, 2004 and September 30, 2003.

Our general and administrative expenses increased to $2.9 million in the nine months ended September 30, 2004 as compared to $1.3 million in the nine months ended September 30, 2003, an increase of $1.6 million. This increase includes $484,000 of general and administrative expenses associated with Spectrum which we acquired on July 16, 2004. In addition, allocations of compensation and benefits from Atlas America and its affiliates increased $221,000 due to an increase in management time spent on our acquisition and public offerings. Additionally, the expensing of phantom units issued under the our Long-Term Incentive Plan and the related distributions on those units increased general and administrative expense by $419,000. Also, an increase of $268,000 resulted from costs associated with the implementation of Sarbannes-Oxley and the preparation and filing of two tax returns for 2003. The filing of two tax returns was a result of our general partner s percentage interest in us being reduced below 50% as a result of our offering of common units in May 2003, requiring a change in our tax year-end from September 30th to December 31st which necessitated the filing of an additional short year tax return. This expense is non-recurring.

Our depreciation and amortization expense increased to $2.1 million in the nine months ended September 30, 2004 as compared to $1.3 million in the nine months ended September 30, 2003, an increase of $866,000. This increase resulted from the acquisition of Spectrum ($613,000), and our increased asset base associated with pipeline extensions and the upgrade of compressors and compressor stations. We anticipate that our depreciation will increase in the remainder of 2004 as a result of both these factors.

Our interest expense increased to $1.2 million in the nine months ended September 30, 2004 as compared to $212,000 in the nine months ended September 30, 2003. This increase of $990,000 resulted from increased borrowings in the nine months ended September 30, 2004 as compared to the same period in 2003. In July 2004, we borrowed $100.0 million to partially fund our acquisition of Spectrum. Subsequently, in July 2004, we repaid $40.0 million of these borrowings upon the completion of our public offering. Our interest expense in the nine months ended September 30, 2003 consisted of fees on our outstanding borrowings, commitment fees on amounts not drawn on our credit facility and amortization of our debt issuance costs.

Our terminated acquisition costs are related to the acquisition of Alaska Pipeline Company, which was purportedly terminated in July 2004. These costs consist primarily of legal and professional fees. In September 2003, we entered into an agreement with SEMCO to purchase all of the stock of Alaska Pipeline Company. In order to complete the acquisition, we needed the approval of the Regulatory Commission of Alaska. The Regulatory Commission initially approved the transaction, but on June 4, 2004 it vacated its order of approval based upon a motion for clarification or reconsideration filed by SEMCO. On July 1, 2004, SEMCO sent us a notice purporting to terminate the transaction. We believe SEMCO caused the delay in closing the transaction and breached its obligations under the acquisition agreement. We are currently pursuing our remedies under the acquisition agreement. In connection with the acquisition, subsequent termination and current legal action, we incurred $3.0 million of costs, which are shown as terminated acquisition costs on our income statement.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses, are for debt service, maintenance capital expenditures, expansion capital expenditures and quarterly distributions to our unitholders and general partner. In addition to cash generated from operations, we have the ability to meet our cash requirements, (other than distributions to our unitholders and general partner) through borrowings under our credit facility. 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, additional borrowings and the issuance of additional common units; and
- debt principal payments through additional borrowings as they become due or by the issuance of additional common units.

At September 30, 2004, we had outstanding borrowings of $60.0 million and had $72.5 million of remaining borrowing capacity under our credit facility.

The following table summarizes our financial condition and liquidity at the dates indicated:

	September 30, 2004	December 31, 2003
		(Unaudited)
Current ratio	1.30x	2.88x
Working capital (in thousands)	$ 9,575	$ 9,890

We had $29.0 million in cash and cash equivalents at September 30, 2004, as compared to $15.1 million at December 31, 2003. The increase in cash is primarily the result of proceeds remaining from our July 2004 public offering.

Net cash provided by operations of $17.7 million in the nine months ended September 30, 2004 increased $6.3 million from $11.5 million in the nine months ended September 30, 2003. The increase in cash flows provided by operations in 2004 was principally due to an increase in accounts payable-affiliate which increased cash flows as a result of advances from Atlas America in connection with expenses associated with the acquisition of Spectrum and the terminated Alaska Pipeline acquisition.

Net cash used in investing activities was $145.7 million for the nine months ended September 30, 2004, an increase of $140.7 million from $5.0 million in the nine months ended September 30, 2003. The primary reason for this increase was the acquisition of Spectrum.

Net cash provided by financing activities was $141.9 million for the nine months ended September 30, 2004, an increase of $130.1 million from $11.8 million in the nine months ended September 30, 2003. The primary reason for the increase was proceeds received from our April 2004 and July 2004 public offerings and net borrowings of $60.0 million on our revolving credit facility to fund our acquisition of Spectrum. This increase was partially offset by an increase in distributions to partners in the current year period as a result of an increase in net cash flow from operations and units outstanding.

Capital Expenditures

Our property, plant and equipment were approximately 78% and 60% of our total consolidated assets at September 30, 2004 and December 31, 2003, respectively. Capital expenditures were $4.4 million in the nine months ended September 30, 2004 as compared to $4.1 million in the nine months ended September 30, 2003. These capital expenditures principally consisted of costs relating to the expansion of our existing gathering systems to accommodate new wells drilled in our Appalachian Basin service area and compressor upgrades. During the twelve months ended September 30, 2004, we connected 337 wells to our Appalachian Basin gathering systems. As of September 30, 2004, we were committed to expend approximately $2.5 million for further pipeline extensions and compressor upgrades. We also anticipate that capital expenditures will increase in the remainder of 2004 as a result of an increase in the number of wells we estimate will be connected to our gathering systems.

Credit Facilities

On July 16, 2004 we obtained a $135.0 million credit facility administered by Wachovia Bank that replaced our existing $20.0 million facility. The facility includes a $75.0 million four-year revolving line of credit which can be increased by an additional $40.0 million under certain circumstances and a $60.0 million five-year term loan. Up to $5.0 million of the facility may be used for standby letters of credit. Borrowings under the facility are secured by a lien on and security interest in all of our property and that of our subsidiaries and by the guaranty of each of our subsidiaries. The credit facility bears interest at one of two rates, elected at our option:

- o the base rate plus the applicable margin; or
- o the adjusted London Interbank Offered Rate, or LIBOR, plus the applicable margin.

The base rate for any day equals the higher of the federal funds rate plus 1/2 of 1% or the Wachovia Bank prime rate. Adjusted LIBOR is LIBOR divided by 1.00 minus the percentage prescribed by the Board of Governors of the Federal Reserve System for determining the reserve requirement for euro currency funding. The applicable margin for the revolving line of credit is as follows:

- o where our leverage ratio, that is, the ratio of our debt to our earnings before interest, taxes, depreciation and amortization, or EBITDA, is less than or equal to 2.5, the applicable margin is 1.00% for base rate loans and 1.75% for LIBOR loans;
- o where our leverage ratio is greater than 2.5 but less than or equal to 3.0, the applicable margin is 1.25% for base rate loans and 2.00% for LIBOR loans;

- o where our leverage ratio is greater than 3.0 but less than or equal to 3.5, the applicable margin is 1.75% for base rate loans and 2.50% for LIBOR loans; and
- o where our leverage ratio is greater than 3.5, the applicable margin is 2.25% for base rate loans and 3.00% for LIBOR loans.

The applicable margin for the term loan is .75% higher for both base rate loans and LIBOR loans.

The credit facility requires us to maintain a ratio of funded debt to EBITDA of not more than 4.25 to 1.0, reducing to 4.0 to 1.0 on December 31, 2004 and 3.5 to 1.0 on September 30, 2005 and an interest coverage ratio of not less than 3.0 to 1.0. In addition, we must prepay the term loan with the net proceeds of any asset sales or issuances of debt. With respect to any issuances of equity, we must repay the term loan from the proceeds of such issuances to the extent our ratio of funded debt to EBITDA exceeds 3.5 to 1.0. We must pay down $750,000 in principal on the outstanding balance of the term loan quarterly, any prepayments of principal with proceeds from equity and asset sales will be credited pro rata against this repayment obligation.

The credit agreement contains covenants customary for loans of this size, including restrictions on incurring additional debt and making material acquisitions, other than the Spectrum acquisition, and a prohibition on paying distributions to our unitholders if an event of default occurs. The events which constitute an event of default are also customary for loans of this size, including payment defaults, breaches of our representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our general partner.

Contractual Obligations and Commercial Commitments

The following tables summarize our contractual obligations and commercial commitments at September 30, 2004 (in thousands):

Contractual cash obligations:

		Payments Due By Period			
	Total	**Less than 1 Year**	**1 - 3 Years**	**3 - 5 Years**	**After 5 Years**
Long-term debt	$ 60,220	$ 3,062	$ 6,122	$ 51,036	$ --
Capital lease obligations	--	--	--	--	--
Operating leases	354	283	71	--	--
Unconditional purchase obligations	--	--	--	--	--
Other long-term obligations	--	--	--	--	--
Total contractual cash obligations	$ 60,574	$ 3,345	$ 6,193	$ 51,036	$ --

The operating leases represent lease commitments for compressors with varying expiration dates. These commitments are routine and were made in the normal course of our business.

Other commercial commitments:

		Amount of Commitment Expiration Per Period			
	Total	**Less than 1 Year**	**1 - 3 Years**	**3 - 5 Years**	**After 5 Years**
Standby letters of credit	$ 2,267	$ 2,267	$ --	$ --	$ --
Guarantees	--	--	--	--	--
Standby replacement commitments	--	--	--	--	--
Other commercial commitments	2,471	2,471	--	--	--
Total commercial commitments	$ 4,738	$ 4,738	$ --	$ --	$ --

Other commercial commitments relate to commitments to make for expenditures for pipeline extensions.

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. We summarize our significant accounting policies in Note 2 to our Consolidated Financial Statements in our annual report on Form 10-K for 2003. The critical accounting policies and estimates that we have identified are discussed as follows.

Revenues and Costs and Expenses

We routinely make accruals for both revenues and costs and expenses due to the timing of receiving information from third parties and reconciling our records with those of third parties. We estimate the accrual amounts using available market data and valuation methodologies. While we believe our estimates are reasonable, actual amounts may vary from estimated amounts.

Depreciation and Amortization

We calculate our depreciation based on the estimated useful lives and salvage values of our assets. However, factors such as usage, equipment failure, competition, regulation or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

Impairment of Assets

In accordance with Statement of Financial Accounting Standard or SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, whenever events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable, we determine if our long-lived assets are impaired by comparing the carrying amount of an asset or group of assets with the estimated future cash flows associated with such asset or group of assets. If the carrying amount is greater than the estimated future cash flows, an impairment loss is recognized in the amount of the excess, if any, of such carrying amount over the fair value of the asset or group of assets.

Goodwill

At September 30, 2004, we had $2.3 million of goodwill, all of which relates to our acquisition of pipeline assets. We test our goodwill for impairment each year. Our test during 2003 resulted in no impairment. We will continue to evaluate our goodwill at least annually and will reflect the impairment of goodwill, if any, in operating income in the income statement in the period in which the impairment is indicated. Our next annual evaluation of goodwill for impairment will be as of December 31, 2004.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 do not engage in any interest rate or foreign currency exchange rate hedging transactions, and as a result, we do not have exposure to these risks.

Our major market risk exposure is in the pricing applicable to natural gas, NGL and crude oil sales which in turn affect our revenues. Realized pricing is primarily driven by spot market prices for these commodities. Pricing for these commodities have been volatile and unpredictable for several years.

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 contract mix, we have a long NGL position and a long gas position. Based upon our portfolio of supply contracts, without giving effect to hedging activities that would reduce the impact of commodity price decreases, a decrease of $0.01 per gallon in the price of NGLs and $0.10 per million BTUs in the average price of natural gas would result in changes in annual net income of approximately $227,000 and $146,000, respectively. In addition, a decrease of $1 per barrel in the average price of crude oil would result in a change to annual income of approximately $46,000.

During the first nine months of 2004, substantially all of our gross margin is generated by commodity sensitive arrangements and approximately 20% of our gross margin (excluding hedging and including earnings of unconsolidated affiliates) was generated by fee-based arrangements. We actively manage our commodity exposure as discussed below.

Market risk inherent in our debt is the potential change arising from increases or decreases in interest rates. Changes in variable rate debt usually do not affect the fair value of the debt instrument, but may affect our future earnings and cash flows.

At September 30, 2004 we had a $75.0 million four-year revolving line of credit which can be increased by an additional $40.0 million under certain circumstances and a $60.0 million five year-term loan, to fund the expansion of our existing gathering systems and the acquisition of other gas gathering systems. We had $60.0 million drawn on this facility at September 30, 2004. The weighted average interest rate for borrowings under our credit facility was 6.0% at September 30, 2004. Holding all other variables constant, if interest rates hypothetically increased or decreased by 10% our net income would change by approximately $362,000.

In our Mid-Continent business, we entered into certain financial swap instruments, some of which settled during the three months ended September 30, 2004 that are designated as cash flow hedging instruments in accordance with SFAS 133. The maturities of the instruments outstanding at September 30, 2004, are less than three years. The swap instruments are contractual agreements to exchange obligations of money between the buyer and seller of the instruments as natural gas, natural gas liquid and crude oil volumes during the pricing period are sold. The swaps are tied to a set fixed price for the seller and floating price determinants for the buyer priced on certain indices at the end of the relevant trading period. Options have also been entered that fix the price for the seller within the puts purchased and calls sold and floating price determinants for the buyer priced on certain indices at the end of the relevant trading period. We entered into these instruments to hedge the forecasted gas plant residue, NGLs and condensate sales to variability in expected future cash flows attributable to changes in market prices. For the instruments that were settled during the three months ended September 30, 2004, we recognized a loss of $27,000.

We entered into several swaps that were designed to hedge natural gas liquid prices during the three months ended September 30, 2004 that did not meet specific hedge accounting criteria. The Partnership recognized a loss of $697,000 related to these instruments during the three months ended September 30, 2004.

As of September 30, 2004, we had the following natural gas liquids, natural gas, and crude oil volumes hedged.

Natural Gas Liquids Fixed-Price Swaps

Natural Gas Liquids Fixed-Price Swaps

Production Period	Volumes (Gallons)	Average Fixed Price	Fair Value Liability
		(per gallon)	(in thousand)
2004	2,562,000	$ 0.645	$ (282)
2005	10,584,000	0.537	(2,524)
2006	6,804,000	0.575	(1,030)
			$ (3,836)

Natural Gas Fixed Price Swaps

Production Period	Volumes (MMBTU)(1)	Average Fixed Price	Fair Value Liability
		(per MMBTU)	(in thousand)
2005	960,000	$ 6.165	$ (697)
2006	450,000	5.920	(160)
			$ (857)

Natural Gas Options

Production Period	Option Type	Volumes (MMBTU)[1]	Average Strike Price	Fair Value Asset (Liability)
			(per MMBTU)	(in thousand)
2004	Puts purchased	150,000	$ 5.700	$ 7
2004	Calls sold	150,000	6.970	(41)
2005	Puts purchased	180,000	5.875	--
2005	Calls sold	180,000	7.110	(179)
				$ (179)

Crude Fixed price Swaps

Production Period	Volumes (Barrels)	Average Fixed Price	Fair Value Liability
		(per barrel)	(in thousand)
2006	18,000	$ 38.767	$ (31)

Crude Options

Production Period	Option Type	Volumes (Barrels)	Average Strike Price	Fair Value Liability
			(per barrel)	(in thousands)
2004	Puts purchased	25,000	$ 32.200	$ --
2004	Calls sold	25,000	38.560	(244)
2005	Puts purchased	75,000	30.067	--
2005	Calls sold	75,000	34.383	(846)
2006	Puts purchased	5,000	30.000	--
2006	Calls sold	5,000	34.250	(39)
				$ (179)

(1) MMBTU means Million British Thermal Units.

As of September 30, 2004, the fair value of the swap agreements we had entered into in order to convert our market-sensitive floating price contracts to fixed-price positions resulted in a $6.0 million liability.

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 general partner, including the Chief Executive Officer and Chief Financial Officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our general partner and its 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 general partner s management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of the Chief Executive Officer and Chief Financial Officer of our general partner, and with the participation of the 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, the Chief Executive Officer and Chief Financial Officer of our general partner concluded that our disclosure controls and procedures are effective at the reasonable assurance level.

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

PART II. OTHER INFORMATION

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits:

Exhibit No.	Description
2.1	Securities Purchase Agreement, dated June 10, 2004, among Atlas Pipeline Operating Partnership, L.P. and Spectrum Field Services, Inc., et al. (1)
3.1	Second Amended and Restated Agreement of Limited Partnership (2)
3.2	Certificate of Limited Partnership of Atlas Pipeline Partners, L.P. (3)
10.1	Revolving Credit and Term Loan Agreement among Atlas Pipeline Partners, L.P., Wachovia Bank, National Association and other parties thereto, dated July 16, 2004
10.1(a)	Notice of Increase of Aggregate Maximum Revolver Amount, dated August 17, 2004
31.1	Rule 13a-14(a)/15d-14(a) Certifications
31.2	Rule 13a-14(a)/15d-14(a) Certifications
32.1	Section 1350 Certifications
32.2	Section 1350 Certifications

(1) Previously filed as an exhibit to the Partnership s current report on Form 8-K filed July 13, 2004 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.

(b) Reports on Form 8-K:

During the quarter ended June 30, 2004, the Partnership filed four current reports on Form 8-K as follows:

- We filed a Form 8-K on April 8, 2004 regarding our public offering of up to 862,500 common units pursuant to a registration statement.
- We filed a Form 8-K on June 9, 2004 regarding SEMCO Energy, Inc. s petition with the Regulatory Commission of Alaska seeking classification of their order issued on April 20, 2004 in connection with approvals sought by us and SEMCO Energy, Inc. in connection with the proposed sale of Alaska Pipeline Company to us.
- We filed a Form 8-K on June 15, 2004 regarding our belief that SEMCO Energy, Inc. had breached its obligations under the Purchase and Sale Agreement with respect to the sale of Alaska Pipeline Company to us.

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

Dated: November 8, 2004

By: /s/ Freddie M. Kotek
Freddie M. Kotek
Chief Financial Officer of the General Partner

Dated: November 8, 2004

By: /s/ Nancy J. McGurk
Nancy J. McGurk
Chief Accounting Officer of the General Partner