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

FORM 10-Q

(Mark one)

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **March 31, 2005**

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 **1-08246**

SOUTHWESTERN ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Arkansas	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2350 N. Sam Houston Pkwy. E., Suite 300, Houston, Texas 77032
(Address of principal executive offices, including zip code)

(281) 618-4700
(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year; if changed since last report)

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 twelve 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: ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding at April 29, 2005
Common Stock, Par Value $0.10	36,458,330

PART I

FINANCIAL INFORMATION

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended March 31, 2005	2004
	(in thousands, except share/per share amounts)	
Operating Revenues:		
Gas sales	$ 126,271	$ 101,019
Gas marketing	24,547	9,186
Oil sales	6,111	4,334
Gas transportation and other	4,124	5,251
	161,053	119,790
Operating Costs and Expenses:		
Gas purchases - utility	33,823	31,532
Gas purchases - marketing	23,198	8,063
Operating expenses	11,933	9,712
General and administrative expenses	10,303	8,010
Depreciation, depletion and amortization	20,247	15,526
Taxes, other than income taxes	5,323	3,640
	104,827	76,483
Operating Income	56,226	43,307
Interest Expense:		
Interest on long-term debt	4,923	4,421
Other interest charges	310	512
Interest capitalized	(695)	(548)
	4,538	4,385
Other Income (Expense)	184	321
Income Before Income Taxes and Minority Interest	51,872	39,243
Minority Interest in Partnership	(93)	(399)
Income Before Income Taxes	51,779	38,844
Provision for Income Taxes - Deferred	19,158	14,372
Net Income	$ 32,621	$ 24,472
Earnings Per Share:		
Basic	$ 0.90	$ 0.69
Diluted	$ 0.87	$ 0.67
Weighted Average Common Shares Outstanding:		
Basic	36,125,860	35,549,453
Diluted	37,456,127	36,614,578

The accompanying notes are an integral part of the financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	March 31, 2005	December 31, 2004
	(in thousands)	
Current Assets		
Cash	$ 857	$ 1,235
Accounts receivable	77,020	86,268
Deferred income tax assets	24,300	3,600
Inventories, at average cost	16,258	32,248
Other	5,307	7,634
Total current assets	123,742	130,985
Investments	15,614	15,465
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	1,561,508	1,483,824
Gas distribution systems	209,345	207,447
Gas in underground storage	32,254	32,254
Other	38,327	37,820
	1,841,434	1,761,345
Less: Accumulated depreciation, depletion and amortization	797,372	777,189
	1,044,062	984,156
Other Assets	16,841	15,538
Total Assets	$ 1,200,259	$ 1,146,144

The accompanying notes are an integral part of the financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	March 31, 2005	December 31, 2004
	(in thousands)	
Current Liabilities		
Accounts payable	$ 79,729	$ 81,586
Taxes payable	8,320	9,333
Hedging liability - FAS No. 133	71,768	29,886
Over-recovered purchased gas costs	9,007	1,412
Other	15,281	11,483
Total current liabilities	184,105	133,700
Long-Term Debt	298,000	325,000
Other Liabilities		
Deferred income taxes	220,606	203,996
Other	42,689	23,912
	263,295	227,908
Commitments and Contingencies		
Minority Interest in Partnership	11,951	11,859
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 37,225,584 shares	3,723	3,723
Additional paid-in capital	129,198	128,753
Retained earnings	383,082	350,461
Accumulated other comprehensive income (loss)	(58,832)	(19,816)
Common stock in treasury, at cost, 760,613 shares at March 31, 2005 and 821,576 shares at December 31, 2004	(8,486)	(9,156)
Unamortized cost of restricted shares issued under stock incentive plan, 316,648 shares at March 31, 2005 and 320,288 shares at December 31, 2004	(5,777)	(6,288)
	442,908	447,677
Total Liabilities and Shareholders' Equity	$ 1,200,259	$ 1,146,144

The accompanying notes are an integral part of the financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the three months ended March 31, 2005	For the three months ended March 31, 2004
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 32,621	$ 24,472
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	21,257	16,489
Deferred income taxes	19,158	14,372
Ineffectiveness of cash flow hedges	636	979
Equity in income of NOARK partnership	(149)	(192)
Minority interest in partnership	93	399
Change in operating assets and liabilities:		
Accounts receivable	9,248	4,875
Under/over-recovered purchased gas costs	7,595	884
Inventories	16,012	15,093
Accounts payable	(6,724)	(2,901)
Taxes payable	(1,013)	547
Interest payable	4,058	3,884
Other operating assets and liabilities	307	(2,161)
Net cash provided by operating activities	103,099	76,740
Cash Flows From Investing Activities		
Capital expenditures	(80,361)	(50,551)
Proceeds from sale of gas and oil properties	700	-
Other items	517	(285)
Net cash used in investing activities	(79,144)	(50,836)
Cash Flows From Financing Activities		
Payments on revolving long-term debt	(105,200)	(151,800)
Borrowings under revolving long-term debt	78,200	128,000
Debt issuance costs	(1,180)	(1,428)
Change in bank drafts outstanding	3,191	(2,596)
Proceeds from exercise of common stock options	656	1,726
Net cash used in financing activities	(24,333)	(26,098)
Decrease in cash	(378)	(194)
Cash at beginning of year	1,235	1,277
Cash at end of period	$ 857	$ 1,083

The accompanying notes are an integral part of the financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Common Stock		Additional	Retained	Accumulated Other	Common	Unamortized Restricted	
	Shares	Amount	Paid-In Capital	Earnings	Comprehensive Income (Loss)	Stock in Treasury	Stock Awards	Total
					(in thousands)			
Balance at December 31, 2004	37,226	$ 3,723	$ 128,753	$ 350,461	$ (19,816)	$ (9,156)	$ (6,288)	$ 447,677
Comprehensive income:								
Net income	-	-	-	32,621	-	-	-	32,621
Change in value of derivatives	-	-	-	-	(39,016)	-	-	(39,016)
Total comprehensive income	-	-	-	-	-	-	-	(6,395)
Exercise of stock options	-	-	320	-	-	666	-	986
Issuance of restricted stock	-	-	146	-	-	36	(182)	-
Cancellation of restricted stock	-	-	(21)	-	-	(32)	53	-
Amortization of restricted stock	-	-	-	-	-	-	640	640
Balance at March 31, 2005	37,226	$ 3,723	$ 129,198	$ 383,082	$ (58,832)	$ (8,486)	$ (5,777)	$ 442,908

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the three months ended March 31,	
	2005	2004
	(in thousands)	
Balance, beginning of period	$ (19,816)	$ (12,520)
Current period reclassification to earnings	1,239	2,695
Current period change in derivative instruments	(40,255)	(9,692)
Balance, end of period	$ (58,832)	$ (19,517)

The accompanying notes are an integral part of the financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
March 31, 2005

(1) BASIS OF PRESENTATION

The financial statements included herein are unaudited; however, such information reflects all adjustments (consisting solely of normal recurring adjustments) which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. The Company's significant accounting policies are summarized in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2004 (the "2004 Annual Report on Form 10-K").

(2) GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to its natural gas and oil properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of this ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. At March 31, 2005, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At March 31, 2005, our standardized measure was calculated based upon quoted market prices of $7.17 per Mcf for Henry Hub gas and $55.40 per barrel for West Texas Intermediate oil, adjusted for market differentials. A decline in natural gas and oil prices from March 31, 2005 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

(3) EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each period. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental number of shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock. All of the Company's outstanding options at March 31, 2005 (2,160,592 options with an average exercise price of $12.76) were included in the calculation of diluted shares. At March 31, 2004, options for 48,000 shares, with an average exercise price of $24.78 per share, were not included in the calculation of diluted shares because they would have had an antidilutive effect. The remaining options for 2,348,911 shares at March 31, 2004, with a weighted average exercise price of $10.43, were included in the calculation of diluted shares. Restricted shares included in the calculation of diluted shares were 198,799 and 171,638 at March 31, 2005 and 2004, respectively.

(4) DEBT

Debt balances as of March 31, 2005 and December 31, 2004 consisted of the following:

	March 31, 2005	December 31, 2004
	(in thousands)	
Senior notes:		
6.70% Series due December 2005	$ 125,000	$ 125,000
7.625% Series due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Series due 2017	40,000	40,000
	225,000	225,000
Other:		
Variable rate (4.04% at March 31, 2005 and 3.66% at December 31, 2004) unsecured revolving credit arrangements	73,000	100,000
Total debt	$ 298,000	$ 325,000

In January 2005, the Company arranged a new $500 million five-year unsecured revolving credit facility that amended and restated its existing $300 million three-year credit facility that would have expired in January 2007 and replaced a smaller unsecured credit facility that would have matured at the same time. The interest rate on the new credit facility is calculated based upon the Company's debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company's subsidiaries to incur debt. At March 31, 2005, the Company's capital structure consisted of 40% debt (excluding its several guarantee of NOARK's obligations) and 60% equity, with a ratio of EBITDA to interest expense of 16.0, and the Company was in compliance with its debt agreements.

The 6.70% senior notes in the table above are due December 2005. The Company currently intends to use its credit facility to repay these notes and, accordingly, these notes are classified as long-term based upon the Company's ability to fund them on a long-term basis.

(5) DERIVATIVES AND RISK MANAGEMENT

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149, was adopted by the Company on January 1, 2001 and requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement.

At March 31, 2005, the Company's net liability related to its cash flow hedges was $95.6 million. Additionally, at March 31, 2005, the Company had recorded a net of tax cumulative loss to other comprehensive income (equity section of the balance sheet) of $57.8 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Assuming the market prices of futures as of March 31, 2005 remain unchanged, the Company would expect to transfer an aggregate loss of approximately $43.4 million from accumulated other comprehensive income to pre-tax earnings as a loss during the next 12 months. The changes in accumulated other comprehensive income (loss) related to derivatives were losses of $61.9 million ($39.0 million after tax) and $11.1 million ($7.0 million after tax) for the three months ended March 31, 2005 and 2004, respectively. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the application of FAS 133.

(6) SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards No. 131 "Disclosures about Segments of an Enterprise and Related Information." The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of natural gas and crude oil. Revenues for the gas distribution segment arise from the transportation and sale of natural gas at retail. The marketing segment generates revenue through the marketing of both Company and third-party produced gas volumes.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 to the financial statements in the Company's 2004 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes is the sum of operating income, interest expense, other income (expense) and minority interest in partnership. The "Other" column includes items not related to the Company's reportable segments including real estate, pipeline operations and corporate items.

	Exploration And Production	Gas Distribution	Marketing	Other	Total
			(in thousands)		
Three months ended March 31, 2005:					
Revenues from external customers	$ 73,848	$ 62,658	$ 24,547	$ -	$ 161,053
Intersegment revenues	8,695	93	54,518	112	63,418
Operating income	47,731	7,447	1,037	11	56,226
Depreciation, depletion and amortization expense	18,514	1,699	10	24	20,247
Interest expense (1)	3,110	1,095	74	259	4,538
Provision (benefit) for income taxes (1)	16,482	2,353	356	(33)	19,158
Assets	962,378	169,357	25,532	42,992 (2)	1,200,259 (2)
Capital expenditures(3)	78,455	2,082	1	323	80,861

Three months ended March 31, 2004:					
Revenues from external customers	$ 49,245	$ 61,203	$ 9,186	$ 156	$ 119,790
Intersegment revenues	9,826	56	52,074	112	62,068
Operating income	33,429	8,810	887	181	43,307
Depreciation, depletion and amortization expense	13,892	1,601	9	24	15,526
Interest expense (1)	2,906	1,172	63	244	4,385
Provision for income taxes (1)	11,152	2,869	305	46	14,372
Assets	697,470	159,341	17,531	36,660 (2)	911,002 (2)
Capital expenditures(3)	56,583	1,939	--	115	58,637

(1) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense are incurred at the corporate level.
(2) Other assets include the Company's equity investment in the operations of the NOARK Pipeline System, Limited Partnership, corporate assets not allocated to segments, and assets for non-reportable segments.
(3) Exploration and Production capital expenditures include $1.7 million and $8.1 million for the three-month periods ended March 31, 2005 and 2004, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the marketing segment are $49.3 million and $49.0 million for the first quarters of 2005 and 2004, respectively, for marketing of the Company's exploration and production sales. Intersegment sales by the exploration and production segment and marketing segment to the gas distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, prepaid debt costs and prepaid and intangible pension related costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(7) INTEREST AND INCOME TAXES PAID

The following table provides interest and income taxes paid during each period presented:

	For the three months ended March 31,	
	2005	2004
	(in thousands)	
Interest payments	$ 886	$ 379
Income tax payments	$ --	$ --

(8) CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. At March 31, 2005 and December 31, 2004, the outstanding principal for these notes was $67.0 million. The Company's share of the several guarantee is 60%. The notes were issued in June 1998 and require semi-annual principal payments of $1.0 million. Under the several guarantee, the Company is required to fund its share of NOARK's debt service to the extent not funded by operations of the pipeline. Additionally, the Company's gas distribution subsidiary has a transportation contract for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system under which approximately $1.3 million in costs have been incurred by our gas distribution subsidiary in 2005. This contract expires in 2014.

The Company leases certain office space and equipment under non-cancelable operating leases expiring through 2013. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At March 31, 2005, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $1,308,000 in 2005, $1,550,000 in 2006, $1,548,000 in 2007, $1,488,000 in 2008, $1,496,000 in 2009 and $2,477,000 thereafter. Total rent expense for all operating leases was $325,000 in the first quarter of 2005 and $225,600 in the first quarter of 2004.

The Company's utility segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties. These costs are recoverable from the utility's end-use customers. At March 31, 2005, future payments under these non-cancelable demand contracts are $6,610,000 in 2005, $8,589,000 in 2006, $8,815,000 in 2007, $9,202,000 in 2008, $9,588,000 in 2009 and $51,643,000 thereafter. Additionally, the E&P segment has a commitment to a third party for demand transportation charges. At March 31, 2005, future payments under these non-cancelable demand contracts are $1,528,000 in 2005, $1,409,000 in 2006, $677,000 in 2007, $617,000 in 2008, $617,000 in 2009 and $412,000 thereafter.

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

The Company is subject to litigation and claims that arise in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

A lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. We are in the process of filing a motion for rehearing with the Thirteenth Court of Appeals and, if such motion is denied, we intend to pursue this decision to the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by the Company and our legal counsel, no accrual for loss is currently recorded.

(9) ACCOUNTING FOR STOCK-BASED COMPENSATION

Stock-based employee compensation issued pursuant to the Company's plans is accounted for under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-based employee compensation cost related to stock options is reflected in net income as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company does record compensation cost for the amortization of restricted stock shares issued to employees. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (FAS 123), to stock-based employee compensation.

	For the three months ended March 31,	
	2005	2004
	(in thousands, except per share)	
Net Income, as reported	$ 32,621	$ 13,642
Add back: Amortization of restricted stock	403	434
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(813)	(715)
Pro forma net income	$ 32,211	$ 13,361
Earnings per share:		
Basic-as reported	$ 0.90	$ 0.48
Basic-pro forma	0.89	0.47
Diluted-as reported	0.87	0.47
Diluted-pro forma	0.86	0.46

There were no options granted in the first three months of 2005. There were 7,000 options granted in the first three months of 2004 with a fair value of $0.9 million. The fair value of each option grant in 2004 was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: no dividend yield; expected volatility of 47.1%; risk-free interest rate of 3.7%; and expected lives of 6 years.

As discussed further in Note 12 below, "New Pronouncements," the Company will adopt the provisions of FAS 123 (Revised 2004) in the first quarter of 2006. This standard will require the recognition of the fair value cost of equity awards, including stock options, as an expense over the service period provided by employees and directors.

(10) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. Net periodic pension and other postretirement benefit costs include the following components for the three-month periods ended March 31, 2005 and 2004:

	Pension Benefits	
	For the three months ended March 31,	
	2005	2004
	(in thousands)	
Service cost	$ 631	$ 601
Interest cost	941	923
Expected return on plan assets	(1,194)	(1,136)
Amortization of prior service cost	110	111
Amortization of net loss	81	58
Net periodic benefit cost	$ 569	$ 557

	Postretirement Benefits	
	For the three months ended March 31,	
	2005	2004
	(in thousands)	
Service cost	$ 43	$ 43
Interest cost	50	63
Expected return on plan assets	(14)	(10)
Amortization of net loss	10	22
Amortization of transition obligation	22	25
Net periodic benefit cost	$ 111	$ 143

We currently expect to contribute $2.5 million to our pension plans and $0.4 million to our postretirement benefit plans in 2005, which is up from our original estimates as of December 31, 2004 of $2.0 million and $0.4 million, respectively. As of March 31, 2005, there have been no contributions made to our pension plans, and $0.1 million has been contributed to our postretirement benefit plans.

(11) ASSET RETIREMENT OBLIGATIONS

Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," (FAS 143) was adopted by the Company on January 1, 2003. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company owns natural gas and oil properties which require expenditures to plug and abandon the wells when reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period the liability is incurred (at the time the wells are drilled or acquired). The following table summarizes the Company's activity related to asset retirement obligations for the three month period ended March 31, 2005 and for the year ended December 31, 2004:

	2005	2004
	(in thousands)	
Asset retirement obligation at January 1	$ 8,565	$ 7,544
Accretion of discount	84	314
Obligations incurred	203	803
Obligations settled/removed	(1,093)	(133)
Revisions of estimates	(285)	37
Asset retirement obligation at March 31, 2005 and December 31, 2004	$ 7,474	$ 8,565
Current liability	140	473
Long-term liability	7,334	8,092
Asset retirement obligation at March 31, 2005 and December 31, 2004	$ 7,474	$ 8,565

For the three months ended March 31, 2005, the obligations settled/removed includes $0.8 million of obligations removed due to the sale of oil and gas properties. The liability for the plugging and abandonment of these properties was assumed by the buyer.

(12) NEW PRONOUNCEMENTS

In December 2004, the FASB issued Statement on Financial Accounting Standards No. 123 (Revised 2004), "Share-Based Payment," revising FASB Statement 123, "Accounting for Stock-Based Compensation" and superseding APB opinion No. 25, "Accounting for Stock Issued to Employees." This statement requires a public entity to measure the cost of services provided by employees and directors received in exchange for an award of equity instruments, including stock options, at a grant-date fair value. The fair value cost is then recognized over the period that services are provided.

In April 2005, the staff of the Securities and Exchange Commission issued Staff Accounting Bulletin No. 107 (SAB 107) to provide additional guidance regarding the application of FAS 123 (Revised 2004). SAB 107 permits registrants to choose an appropriate valuation technique or model to estimate the fair value of share options, assuming consistent application, and provides guidance for the development of assumptions used in the valuation process. Additionally, SAB 107 discusses disclosures to be made under "Management's Discussion and Analysis of Financial Condition and Results of Operations" in registrants' periodic reports.

Based upon SEC rules issued in April 2005, FAS 123 (Revised 2004) is effective for fiscal years that begin after June 15, 2005 and will be adopted by the Company in the first quarter of 2006. See Note 9 of these financial statements for a disclosure of the effect of net income and earnings per share for the first three months of 2004 and 2005 if the Company had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

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

The following updates information as to Southwestern Energy Company's financial condition provided in our 2004 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three-month periods ended March 31, 2005 and 2004. For definitions of commonly used gas and oil terms as used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2004 Annual Report on Form 10-K.

This Form 10-Q contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in "Risk Factors" and elsewhere in our 2004 Annual Report on Form 10-K. You should read the following discussion with our financial statements and related notes included in this Form 10-Q.

OVERVIEW

Southwestern Energy Company is an integrated energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We also operate integrated natural gas distribution systems in northern Arkansas. As a complement to our other businesses, we provide marketing and transportation services in our core areas of operation. We operate our business in three segments: Exploration and Production, Natural Gas Distribution and Natural Gas Marketing.

Our financial and operating results depend on a number of factors, including in particular natural gas and oil prices, our ability to economically find and produce natural gas and oil, our ability to control costs, the seasonality of our customers' need for natural gas and our ability to market natural gas and oil on economically attractive terms to our customers, all of which are dependent upon numerous factors beyond our control such as economic, political and regulatory developments and competition from other energy sources. There has been significant price volatility in the natural gas and crude oil market in recent years. The volatility was attributable to a variety of factors impacting supply and demand, including weather conditions, political events and economic events we cannot control or predict. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and our reported amounts of assets, liabilities and proved reserves. We use the full cost method to account for our oil and gas activities, as discussed in Note 2 to the financial statements in this Form 10-Q.

We derive our revenues primarily from our three operating segments. Our revenues for the first quarter of 2005 were approximately 34% higher than the comparable period in 2004 due primarily to higher market-driven commodity prices received for our gas and oil sales. We reported net income of $32.6 million, or $0.87 per share on a diluted basis, on revenues of $161.1 million for the three months ended March 31, 2005, up from $24.5 million, or $0.67 per diluted share, on revenues of $119.8 million for the same period in 2004. Operating income for our E&P segment was $47.7 million for the quarter ended March 31, 2005, up from $33.4 million for the same period in 2004. The increases in our net income and in the operating income for the E&P segment were primarily due to a

22% increase in production volumes and higher realized natural gas and oil prices, which were partially offset by an increase in our operating costs and expenses. Operating income from our gas distribution segment was $7.4 million for the three months ended March 31, 2005, compared to $8.8 million for the same period in 2004. The decrease in operating income for our gas distribution segment resulted primarily from decreased deliveries due to warmer weather and increased operating costs and expenses.

In the first quarter of 2005, our gas and oil production increased to 14.0 Bcfe, up from 11.4 Bcfe in the first quarter of 2004. The increase in 2005 production primarily resulted from an increase in production from our Overton Field in East Texas, increased production in the Arkoma Basin and increased production from the development of our River Ridge discovery in New Mexico.

Our capital investments totaled $80.9 million for the first quarter of 2005, up from $58.6 million in the first quarter of 2004. We invested $78.5 million in our E&P segment in the first quarter of 2005, compared to $56.6 million for the same period in 2004.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended March 31,	
	2005	2004
Revenues (in thousands)	$82,543	$59,071
Operating income (in thousands)	$47,731	$33,429
Gas production (MMcf)	13,019	10,516
Oil production (MBbls)	161	152
Total production (MMcfe)	13,987	11,428
Average gas price per Mcf, including hedges	$5.71	$4.92
Average gas price per Mcf, excluding hedges	$5.72	$5.34
Average oil price per Bbl, including hedges	$37.87	$28.43
Average oil price per Bbl, excluding hedges	$47.54	$33.88
Average unit costs per Mcfe		
Lease operating expenses	$0.45	$0.38
General & administrative expenses	$0.39	$0.39
Taxes, other than income taxes	$0.33	$0.26
Full cost pool amortization	$1.29	$1.18

Revenues. Revenues for our E&P segment were up 40% to $82.5 million for the three months ended March 31, 2005, as compared to $59.1 million for the same period in 2004. The increase was primarily due to increased production volumes and higher gas and oil prices realized for our production. Revenues for the first three months of 2005 and 2004 also include pre-tax gains of $2.1 million and $3.0 million, respectively, related to the sale of gas in storage inventory.

Operating Income. Operating income for the E&P segment was up 43% to $47.7 million for the first quarter of 2005, compared to $33.4 million for the same period in 2004. The increase in operating income resulted from the increase in revenues, as discussed above, partially offset by increased operating costs and expenses.

Production. Gas and oil production during the first quarter of 2005 was 14.0 Bcfe, up 22% from 11.4 Bcfe in the first quarter of 2004. The comparative increase in production primarily resulted from an increase in production from our Overton Field in East Texas, increased production in the Arkoma Basin and increased production from the development of our River Ridge discovery in New Mexico. Production during the first quarter of 2005 included the effects of curtailment of a portion of our production at our Overton Field due to pipeline repairs of a non-operated transmission line into which we deliver a large portion of our gas production. Gas production was 13.0 Bcf for the first quarter of 2005 up from 10.5 Bcf for the first quarter of 2004. Intersegment sales to our gas distribution systems were 1.4 Bcf during the three months ended March 31, 2005, compared to 1.7 Bcf for the same period in 2004. Our oil production was 161 thousand barrels (MBbls) during the first quarter of 2005, up from 152 MBbls for the same period of 2004.

Average Realized Prices. The average price realized for our gas production, including the effect of hedges, was $5.71 per thousand cubic feet (Mcf) for the three months ended March 31, 2005, up from $4.92 per Mcf for the same period of 2004. The change in the average price realized primarily reflects changes in average spot market prices and the effects of our price hedging activities. Our hedging activities had minimal impact on the average gas price realized during the first three months of 2005, compared to a decrease of $0.42 per Mcf during the same period of 2004. Locational differences in market prices for natural gas have continued to be wider than historically experienced. Disregarding the impact of hedges, the average price received for our gas production during the first quarter of 2005 was approximately $0.55 lower than average NYMEX spot prices, compared to the average for the prior year period of approximately $0.35 per Mcf.

We realized an average price of $37.87 per barrel for our oil production, including the effect of hedges, during the three months ended March 31, 2005, up from $28.43 per barrel for the same period of 2004. The average price we received for our oil production in the first three months of 2005 and 2004 was reduced by $9.67 per barrel and $5.45 per barrel, respectively, due to the effects of our hedging activities.

Hedging Activities. We periodically enter into hedging activities with respect to a portion of our projected natural gas and crude oil production through a variety of financial arrangements intended to support natural gas and oil prices at targeted levels and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. For the remainder of 2005, we have hedges in place for 33.2 Bcf of gas production and for 2006 and 2007 we have 41.0 Bcf and 14.0 Bcf, respectively, of our future gas production hedged. For the remainder of 2005, we have hedged 270,000 barrels of our oil production at an average NYMEX price of $33.17 per barrel. For 2006 we have hedged 120,000 barrels of our future oil production. See Part I, Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Lease Operating Expenses. Lease operating expenses per Mcfe for our E&P segment were $0.45 for the first quarter of 2005, compared to $0.38 for the same period in 2004. The increase in lease operating expenses per Mcfe in 2005 resulted from an increase in compression costs and generally higher oil field service costs.

General & Administrative Expenses. General and administrative expenses per Mcfe were $0.39 during both the first quarters of 2005 and 2004. General and administrative expenses for our E&P segment increased to $5.4 million for the first quarter of 2005, compared to $4.4 million for the same period of 2004 due primarily to increased compensation costs associated with increased staffing levels.

Taxes Other Than Income Taxes. Taxes other than income taxes per Mcfe were $0.33 for the first quarter of 2005, compared to $0.26 for the same period in 2004. The increase in severance taxes per Mcfe in 2005 is primarily due to comparatively higher average market prices in effect for natural gas and crude oil, as reflected in the average price received for our production excluding the effect of hedges.

Full Cost Pool Amortization. Our full cost pool amortization rate was $1.29 per Mcfe for the first three months of 2005, compared to $1.18 per Mcfe for the same period in 2004. The increase in our full cost pool amortization rate was primarily due to increased finding and development costs. Depreciation, depletion and amortization expense for our E&P segment increased to $18.5 million for the first three months of 2005, compared to $13.9 million for the same period of 2004 as a result of the 22% increase in our production volumes and the increase in the per unit rate of amortization.

Full Cost Pool Ceiling. We utilize the full cost method of accounting for capitalizing costs related to our natural gas and oil properties. As discussed in Note 2 to the financial statements, these capitalized costs are subject to a ceiling test that limits our pooled costs and requires us to write-off costs in excess of the ceiling as a non-cash expense. At March 31, 2005, our unamortized costs of gas and oil properties did not exceed the ceiling amount. Our standardized measure at March 31, 2005 was calculated based upon quoted market prices of $7.17 per Mcf for Henry Hub gas and $55.40 per barrel for West Texas Intermediate oil, adjusted for market differentials. A decline in natural gas and oil prices from March 31, 2005 levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Natural Gas Distribution

	For the three months ended March 31, 2005	2004
Revenues (in thousands)	$62,751	$61,259
Gas purchases (in thousands)	$42,495	$41,348
Operating costs and expenses (in thousands)	$12,809	$11,101
Operating income (loss) (in thousands)	$7,447	$8,810
Deliveries (Bcf)		
Sales and end-use transportation	9.2	9.8
Off-system transportation	-	1.0
Customers at period-end	146,684	143,347
Average sales rate per Mcf	$9.16	$8.11
Heating weather - degree days	1,902	2,061
Percent of normal	89%	96%

Revenues. Gas distribution revenues fluctuate due to the pass-through of gas supply cost changes and the effects of weather. Because of the corresponding changes in purchased gas costs, the revenue effect of the pass-through of gas cost changes has not materially affected net income. Revenues for the three-month period ended March 31, 2005 increased 2% from the comparable period of 2004 as increased cost of gas supplies caused by higher gas prices was mostly offset by lower sales volumes.

Operating Income. Operating income for our gas distribution segment decreased $1.4 million in the first quarter of 2005, as compared to the same period of 2004, due to decreased deliveries caused by warmer weather and increased operating costs and expenses. Weather during the first three months of 2005 was 11% warmer than normal and 7% warmer than the same period in 2004.

Deliveries. The utility systems delivered 9.2 Bcf to sales and end-use transportation customers during the three-month period ended March 31, 2005, compared to 9.8 Bcf for the same period in 2004. The decrease in deliveries during the first three months of 2005 was primarily due to the effects of warmer weather and continued customer conservation brought about by high gas prices.

Rates. Our utility's tariffs contain a weather normalization clause intended to lessen the impacts of revenue increases and decreases that might result from weather variations during the winter heating season. The increase in gas costs in the first three months of 2005 was reflected in the utility segment's average rate for its sales which increased to $9.16 per Mcf, up from $8.11 per Mcf for the same period in 2004. The fluctuations in the average sales rate primarily reflect changes in the average cost of gas purchased for delivery to our customers, which are passed through to customers under automatic adjustment clauses.

Hedging Activities. Our utility segment hedged 2.9 Bcf of gas purchases in the first three months of 2005 which had the effect of increasing its total gas supply cost by $1.4 million. In the first three months of 2004, our utility hedged 3.8 Bcf of its gas supply which decreased its total gas supply cost by $0.1 million. See Part I, Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Operating Costs and Expenses. The changes in purchased gas costs for our gas distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from various gas supply contracts (base load, swing and no-notice). Other operating costs and expenses for this segment during the first quarter were higher than the comparable period of the prior year due primarily to higher general and administrative expenses. The increase in general and administrative expense primarily resulted from increased compensation costs.

Marketing

	For the three months ended March 31,	
	2005	2004
Revenues (in thousands)	$79,065	$61,260
Operating income (in thousands)	$1,037	$887
Gas volumes marketed (Bcf)	14.4	12.3

Revenues. Revenues from natural gas marketing were $79.1 million in the first three months of 2005, compared to $61.3 million for the comparable period of 2004. The increase in revenues from natural gas marketing is attributable to increased volumes marketed and an increase in natural gas commodity prices. The increase in revenues was largely offset by a comparable increase in purchased gas costs.

Operating Income. Our operating income from natural gas marketing was $1.0 million in the first quarter of 2005, compared to $0.9 million in the same period of 2004. Operating income from natural gas marketing fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity.

Gas Volumes Marketed. We marketed 10.8 Bcf of affiliated gas in the first quarter of 2005, representing 75% of total volumes marketed, compared to 10.1 Bcf, or 82% of total volumes marketed, for the same period in 2004. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Item 3, "Qualitative and Quantitative Disclosure about Market Risks" in this Form 10-Q for additional information.

Transportation

We recorded pre-tax income from operations related to our investment in the NOARK Pipeline System Limited Partnership (NOARK) of $0.1 million for the first quarter of 2005, compared to $0.2 million for the first quarter of 2004. These amounts were recorded in other income (expense) in our statements of operations.

Interest Expense

Interest costs, net of capitalization, increased 3% for the first quarter of 2005, as compared to the same period of 2004. The increase in interest costs in the first quarter of 2005 primarily resulted from higher average borrowings during the period, partially offset by an increase in capitalized interest. Changes in capitalized interest are primarily due to the level of costs excluded from amortization in our E&P segment.

Income Taxes

Our effective tax rate was 37.0% for the three months ended March 31, 2005 and 2004. The changes in the provision for deferred income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences.

Pension Expense

We recorded pension expense of $0.6 million in both the first quarters of 2005 and 2004. The amount of pension expense recorded by us is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $2.5 million to our pension plans in 2005, which is up from our original estimate of $2.0 million as of December 31, 2004. As of March 31, 2005, no contributions have been made to our pension plans. For further information regarding our pension plans, we refer you to Note 10 of the financial statements in this Form 10-Q.

New Accounting Principles

In December 2004, the FASB issued Statement on Financial Accounting Standards No. 123 (Revised 2004), "Share-Based Payment," revising FASB Statement 123, "Accounting for Stock-Based Compensation" and superseding APB opinion No. 25, "Accounting for Stock Issued to Employees." This statement requires a public entity to measure the cost of services provided by employees and directors received in exchange for an award of equity instruments, including stock options, at a grant-date fair value. The fair value cost is then recognized over the period that services are provided.

In April 2005, the staff of the Securities and Exchange Commission issued Staff Accounting Bulletin No. 107 (SAB 107) to provide additional guidance regarding the application of FAS 123 (Revised 2004). SAB 107 permits registrants to choose an appropriate valuation technique or model to estimate the fair value of share options, assuming consistent application, and provides guidance for the development of assumptions used in the valuation process. Additionally, SAB 107 discusses disclosures to be made under "Management's Discussion and Analysis of Financial Condition and Results of Operations" in registrants' periodic reports.

Based upon SEC rules issued in April 2005, FAS 123 (Revised 2004) is effective for fiscal years that begin after June 15, 2005 and will be adopted by the Company in the first quarter of 2006. See Note 10 of these financial statements for a disclosure of the effect of net income and earnings per share for the first three months of 2004 and 2005 if the Company had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds and our unsecured revolving credit facility (discussed below under "Financing Requirements") as our primary sources of liquidity. We have the ability to borrow up to $500 million under our revolving credit facility from time to time. As of March 31, 2005, we had $73.0 million of indebtedness outstanding under our revolving credit facility. During 2005, we expect to draw on a portion of the funds available under our credit facility to fund our planned capital expenditures (discussed below under "Capital Expenditures"), which are expected to exceed the net cash generated by our operations.

Net cash provided by operating activities was $103.1 million in the first three months of 2005, compared to $76.7 million for the same period of 2004. The primary components of cash provided from operations are net income adjusted for depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. For the first three months of 2005 and 2004, cash provided by operating activities provided 100% of our requirements for capital expenditures.

Our cash flow from operating activities is highly dependent upon market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 5 to the financial statements included in this Form 10-Q and Item 3, "Quantitative and Qualitative Disclosures about Market Risks." Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Expenditures

Our capital expenditures for the first three months of 2005 were $80.9 million, including $1.7 million relating to the effects of accrued expenditures, compared to $58.6 million for the same period in 2004 including $8.1 million relating to the change in the amount of accrued expenditures. Our capital investments for calendar year 2005 are planned to be up to $352.7 million, including up to $339.0 million of capital investments in our E&P segment. Our 2005 capital investment program is expected to be funded through cash flow from operations and borrowings under our revolving credit facility. We may adjust our level of 2005 capital investments dependent upon our level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $298.0 million at March 31, 2005 and $325.0 million at December 31, 2004. The total debt at March 31, 2005 includes $125 million of 6.70% senior notes due December 2005, which we intend to use our credit facility to repay. Of the total outstanding at March 31, 2005, $73.0 million was outstanding under our revolving credit facility. In January 2005, we amended and restated our previous $300 million revolving credit facility due to expire in January 2007, increasing the borrowing capacity to $500 million and extending the expiration to January 2010. The amended and restated credit facility also replaced another smaller credit facility. The interest rate on the new facility is calculated based upon our debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). Our publicly traded notes are rated Ba2 by Moody's and BBB- by Standard & Poor's, following a downgrade from BBB in January 2005. Any future downgrades in our public debt ratings could increase the cost of funds under our revolving credit facility.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreements, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. EBITDA is a measure required by our debt covenants and is defined as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Additionally, there are also restrictions on the ability of our subsidiaries to incur debt. We were in compliance with the covenants of our debt agreements at March 31, 2005. Although we do not anticipate any debt covenant violations, our ability to comply with our credit agreement is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our credit facility, we would have to decrease our capital expenditure plans.

At March 31, 2005, our capital structure consisted of 40% debt (excluding our several guarantee of NOARK's obligations) and 60% equity, with a ratio of EBITDA to interest expense of 16.0. Shareholders' equity in the March 31, 2005 balance sheet includes an accumulated other comprehensive loss of $57.8 million related to our hedging activities that is required to be recorded under the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). This amount is based on the market value of our hedges as of March 31, 2005, and does not necessarily reflect the value that we will receive or pay when the hedges ultimately are settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our debt covenants as to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 as well as the non-cash impact of any full cost ceiling write-downs, and include the guarantee of NOARK's obligations. Our capital structure, including our several guarantee of NOARK's obligations of $40.2 million, would remain at 40% debt and 60% equity at March 31, 2005, without consideration of the accumulated other comprehensive loss related to FAS 133 of $57.8 million. As part of our strategy to insure a certain level of cash flow to fund our operations, we have hedged approximately 70% to 80% of our expected 2005 gas production and 60% to 70% of our expected 2005 oil production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near current levels throughout 2005 and our projected capital expenditures do not change, we will increase our long-term debt during the remainder of 2005. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital expenditures significantly.

Off-Balance Sheet Arrangements

We hold a 25% general partnership interest in NOARK, which owns the Ozark Pipeline that is utilized to transport our gas production and the gas production of others. We account for our investment under the equity method of accounting. We and the other general partner of NOARK have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018 which were issued in June 1998 to partially finance the original construction cost of the NOARK Pipeline. Our share of the guarantee is 60% and we are allocated 60% of the interest expense. At March 31, 2005, the outstanding principal amount of these notes was $67.0 million and our share of the guarantee was $40.2 million. The notes require semi-annual principal payments of $1.0 million. Under the several guarantee, we are required to fund our share of NOARK's debt service which is not funded by operations of the pipeline. We were not required to advance any funds to NOARK in the first quarters of 2005 and 2004. We do not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

Our share of the results of operations included in other income (expense) related to our NOARK investment was pre-tax income of $0.1 million for the first quarter of 2005, compared to $0.2 million for the first quarter of 2004.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations at March 31, 2005 were as follows:

Contractual Obligations

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
			(in thousands)		
Long-term debt	$298,000	$125,000	$ -	$133,000	$40,000
Operating leases[1]	9,866	1,697	3,086	2,984	2,099
Unconditional purchase obligations[2]	-	-	-	-	-
Demand charges[3]	99,705	10,731	19,335	20,216	49,423
Other obligations[4]	5,672	5,622	50	-	-
	$413,243	$143,050	$22,471	$156,200	$91,522

(1) We lease certain office space and equipment under non-cancelable operating leases expiring through 2013.

(2) Our utility segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at March 31, 2005 totaled 1.6 Bcf, comprised of 1.1 Bcf in less than one year, 0.3 Bcf in one to three years, and 0.2 Bcf in three to five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.

(3) Our utility segment has commitments for approximately $94.4 million of demand charges on non-cancelable firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has a commitment for approximately $5.3 million of demand transportation charges.

(4) Our significant other contractual obligations include approximately $2.9 million for funding of benefit plans, approximately $1.0 million of various information technology support and data subscription agreements, approximately $1.1 million for drilling rig commitments, and approximately $0.4 million of land leases.

We refer you to Note 4 of the financial statements for a discussion of the terms of our long-term debt.

Contingent Liabilities or Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. As a result of actuarial data, we expect to record pension expense of approximately $2.3 million in 2005, $0.6 million of which has been recorded in the first three months of 2005. For further information regarding our pension plans, we refer you to Note 10 of the financial statements in this Form 10-Q. In addition, as discussed above in "Off-Balance Sheet Arrangements," we have guaranteed 60% of the principal and interest payments on NOARK's 7.15% Notes due 2018. At March 31, 2005 the outstanding principal of these notes was $67.0 million and our share of the guarantee was $40.2 million. The notes require semi-annual principal payments of $1.0 million. The foregoing obligations represent commitments and contingencies that could create, increase or accelerate our liabilities.

We are subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. A lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. We are in the process of filing a motion for rehearing with the Thirteenth Court of Appeals and, if such motion is denied, we intend to pursue this decision to the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our above-described credit facility. We had negative working capital of $60.4 million at March 31, 2005, compared to negative working capital of $2.7 million at December 31, 2004. At March 31, 2005, we had $427.0 million of available borrowing capacity under our revolving credit facility. Our current assets decreased by 6% in the first three months of 2005 while current liabilities increased 38%. The change in working capital from December 31, 2004 to March 31, 2005 primarily relates to the increase in our current hedging liability.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 7.6 Bcf at $3.14 at March 31, 2005 and 9.3 Bcf at $3.49 at December 31, 2004.

The gas in inventory for the E&P segment is used primarily to supplement field production in meeting the segment's contractual commitments including delivery to customers of our gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the gas distribution segment to the E&P segment, which are passed through to the utility's customers, are a part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in a write down of our gas in storage carrying cost.

FORWARD-LOOKING INFORMATION

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

* the timing and extent of changes in commodity prices for natural gas and oil;
* the timing and extent of our success in discovering, developing, producing and estimating reserves;
* the extent to which the Fayetteville Shale play can replicate the results of other productive shale gas plays;
* the potential for significant variability in reservoir characteristics of the Fayetteville Shale over such a large acreage position;
* our ability to fund our planned capital expenditures;
* our future property acquisition or divestiture activities;

* the effects of weather and regulation on our gas distribution segment;
* increased competition;
* the impact of federal, state and local government regulation;
* the financial impact of accounting regulations and critical accounting policies;
* changing market conditions and prices (including regional basis differentials);
* the comparative cost of alternative fuels;
* conditions in capital markets and changes in interest rates;
* the availability of oil field personnel, services, drilling rigs and other equipment; and
* any other factors listed in the reports we have filed and may file with the SEC.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in our 2004 Annual Report on Form 10-K and this Form 10-Q.

Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of natural gas and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in our 2004 Annual Report on Form 10-K or this Form 10-Q occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 4% of accounts receivable at March 31, 2005. See the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

Revolving debt obligations are sensitive to changes in interest rates. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate, although we do not have any interest rate swaps in effect currently.

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production, to hedge activity in our marketing segment, and to hedge the purchase of gas in our utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX (New York Mercantile Exchange) futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which we pay to (production hedge) or receive from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are periodically reviewed to ensure limited credit risk exposure.

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for our gas and oil production, gas purchases and marketing activities. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), the weighted average contract prices, and the fair value by expected maturity dates. At March 31, 2005, the fair value of these financial instruments was a $95.6 million liability.

	Expected Maturity Date		
	2005	2006	2007
Production and Marketing			
Natural Gas			
Swaps with a fixed price receipt			
Contract Volume (Bcf)	11.7	7.0	12.0
Weighted average price per Mcf	$4.94	$6.27	$6.62
Fair value (in millions)	($34.6)	($8.7)	($3.3)
Price collars			
Contract volume (Bcf)	21.5	34.0	2.0
Weighted average floor price per Mcf	$4.65	$5.03	$6.00
Fair value of floor (in millions)	$0.1	$3.1	$0.7
Weighted average ceiling price per Mcf	$7.14	$9.49	$12.21
Fair value of ceiling (in millions)	($25.6)	($18.5)	($0.6)
Swaps with a fixed price payment			
Contract volume (Bcf)	0.1	-	-
Weighted average price per Mcf	$6.11	-	-
Fair value (in millions)	$0.2	-	-
Oil			
Swaps with a fixed price receipt			
Contract volume (MBbls)	270	120	-
Weighted average price per Bbl	$33.17	$37.30	-
Fair value (in millions)	($6.3)	($2.1)	-

At March 31, 2005, the Company had outstanding fixed-price basis differential swaps on 2.0 Bcf of 2006 and 1.0 Bcf of 2007 gas production that did not qualify for hedge accounting treatment. The fair value of these differential swaps was an asset of $12,752 at March 31, 2005. We entered into additional fixed-price basis differential swaps relating to approximately 2.1 Bcf of May 2005 gas production subsequent to the end of the quarter.

At December 31, 2004, the Company had outstanding natural gas price swaps on total notional volumes of 12.9 Bcf at a weighted average price per Mcf of $5.11 in 2005 and 5.0 Bcf at a weighted average price per Mcf of $5.89 in 2006. Outstanding oil price swaps on 360 MBbls were in place that are yielding the Company an average price of $33.17 per barrel during 2005. At December 31, 2004, the Company also had outstanding natural gas price swaps on total notional gas purchase volumes of 2.9 Bcf in 2005 for which the Company paid an average fixed price of $6.54 per Mcf.

At December 31, 2004, the Company had collars in place on 33.4 Bcf in 2005 and 22.0 Bcf in 2006 of gas production. The 33.4 Bcf in 2005 has a weighted average floor and ceiling price of $4.68 and $8.30 per Mcf, respectively. The 22.0 Bcf in 2006 has a weighted average floor and ceiling price of $4.64 and $8.69 per Mcf, respectively.

ITEM 4. CONTROLS AND PROCEDURES

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, summarize and report the information that is required to be disclosed or submitted by us within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of March 31, 2005. There were no significant changes in our internal control over financial reporting during the three months ended March 31, 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Subsequent to that date, we converted the accounting software systems used for our primary accounting processes and for financial reporting to a new version of software. In connection with the conversion process, we assured our disclosure controls and procedures remained in place and confirmed that our internal controls over financial reporting remained intact.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. A lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. We are in the process of filing a motion for rehearing with the Thirteenth Court of Appeals and, if such motion is denied, we intend to pursue this decision to the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

(31.1) Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(31.2) Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

(32.1) Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Signatures

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.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: April 29, 2005

/s/ GREG D. KERLEY
Greg D. Kerley
Executive Vice President
and Chief Financial Officer