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, 2003**

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 **1-8246**

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 October 24, 2003
Common Stock, Par Value $0.10	35,607,787

PART I

FINANCIAL INFORMATION

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2003	2002	2003	2002
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 52,994	$ 35,656	$ 179,987	$ 140,248
Gas marketing	10,113	10,018	34,386	31,948
Oil sales	3,582	3,728	10,862	11,327
Gas transportation and other	4,379	1,689	10,975	5,230
	71,068	51,091	236,210	188,753
Operating Costs and Expenses:				
Gas purchases - utility	3,496	3,198	32,743	31,770
Gas purchases - marketing	9,025	9,287	31,433	29,414
Operating expenses	9,949	9,698	28,243	28,292
General and administrative expenses	7,937	5,527	23,483	17,351
Depreciation, depletion and amortization	14,896	13,323	40,965	41,061
Taxes, other than income taxes	3,058	2,064	9,016	7,132
	48,361	43,097	165,883	155,020
Operating Income	22,707	7,994	70,327	33,733
Interest Expense:				
Interest on long-term debt	4,324	5,510	13,326	16,209
Other interest charges	350	287	1,072	945
Interest capitalized	(457)	(364)	(1,323)	(1,015)
	4,217	5,433	13,075	16,139
Other Income (Expense)	(476)	(124)	883	(598)
Income Before Income Taxes, Minority Interest & Accounting Change	18,014	2,437	58,135	16,996
Minority Interest in Partnership	(469)	(366)	(1,843)	(1,128)
Income Before Income Taxes & Accounting Change	17,545	2,071	56,292	15,868
Provision for Income Taxes - Deferred	6,667	797	21,391	6,109
Income Before Accounting Change	10,878	1,274	34,901	9,759
Cumulative Effect of Adoption of Accounting Principle	-	-	(855)	-
Net Income	$ 10,878	$ 1,274	$ 34,046	$ 9,759
Basic Earnings Per Share:				
Income Before Accounting Change	$0.31	$0.05	$1.07	$0.39
Cumulative Effect of Adoption of Accounting Principle	-	-	(0.03)	-
Net Income	$0.31	$0.05	$1.04	$0.39
Diluted Earnings Per Share:				
Income Before Accounting Change	$0.30	$0.05	$1.04	$0.37
Cumulative Effect of Adoption of Accounting Principle	-	-	(0.03)	-
Net Income	$0.30	$0.05	$1.01	$0.37
Weighted Average Common Shares Outstanding:				
Basic	35,090,330	25,306,920	32,786,030	25,195,812
Diluted	36,028,157	26,096,616	33,582,506	26,029,923

The accompanying notes are an integral part of the financial statements

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	September 30, 2003	December 31, 2002
	(in thousands)	
Current Assets		
Cash	$ 1,370	$ 1,690
Accounts receivable	39,939	42,115
Inventories, at average cost	29,807	24,735
Under-recovered purchased gas costs	2,076	-
Other	6,667	7,598
Total current assets	79,859	76,138
Investments	13,814	15,287
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	1,152,165	1,030,300
Gas distribution systems	202,685	197,473
Gas in underground storage	37,819	32,395
Other	29,132	31,391
	1,421,801	1,291,559
Less: Accumulated depreciation, depletion and amortization	691,921	659,398
	729,880	632,161
Other Assets	14,899	16,576
Total Assets	$ 838,452	$ 740,162

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	September 30, 2003	December 31, 2002
	(in thousands)	
Current Liabilities		
Short-term debt	$ 37,000	$ -
Accounts payable	43,950	29,881
Taxes payable	3,703	5,213
Interest payable	6,239	2,513
Customer deposits	4,971	4,999
Hedging liability - SFAS No. 133	16,247	20,409
Regulatory liability - hedges	-	3,130
Over-recovered purchased gas costs	-	5,697
Other	3,819	2,715
Total current liabilities	115,929	74,557
Long-Term Debt	225,000	342,400
Other Liabilities		
Deferred income taxes	140,143	116,591
Other	22,842	16,671
	162,985	133,262
Commitments and Contingencies		
Minority Interest in Partnership	12,894	12,455
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 37,225,584 shares	3,723	2,774
Additional paid-in capital	121,130	19,130
Retained earnings	232,034	197,988
Accumulated other comprehensive income (loss)	(13,222)	(17,358)
	343,665	202,534
Less: Common stock in treasury, at cost, 1,623,454 shares at September 30, 2003 and 1,793,456 shares at December 31, 2002	18,196	19,981
Unamortized cost of 495,416 restricted shares at September 30, 2003 and 498,123 restricted shares at December 31, 2002 issued under stock incentive plans	3,825	5,065
	321,644	177,488
Total Liabilities and Shareholders' Equity	$ 838,452	$ 740,162

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

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

	For the nine months ended September 30, 2003	2002
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 34,046	$ 9,759
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	43,130	42,864
Deferred income taxes	21,391	6,109
Ineffectiveness of cash flow hedges	(779)	-
Gain on sale of property and equipment	(2,991)	-
Equity in (income) loss of NOARK partnership	(1,026)	400
Minority interest in partnership	342	(183)
Cumulative effect of adoption of accounting principle	855	-
Change in assets and liabilities:		
Accounts receivable	2,176	19,121
Inventories	(5,072)	(640)
Under/over-recovered purchased gas costs	(7,773)	(3,113)
Accounts payable	6,459	(9,604)
Interest payable	3,726	3,775
Taxes payable	(1,510)	(2,058)
Other operating assets and liabilities	1,877	1,975
Net cash provided by operating activities	94,851	68,405
Cash Flows From Investing Activities		
Capital expenditures	(121,723)	(67,829)
Distribution from NOARK partnership	2,500	-
Proceeds from sale of property and equipment	3,649	-
Increase in gas stored underground	(5,423)	(1,072)
Other items	499	(291)
Net cash used in investing activities	(120,498)	(69,192)
Cash Flows From Financing Activities		
Issuance of common stock	103,085	-
Payments on revolving long-term debt	(229,700)	(144,400)
Borrowings under revolving long-term debt	149,300	147,600
Change in bank drafts outstanding	1,056	(7,623)
Proceeds from exercise of common stock options	1,586	2,077
Net cash provided by (used in) financing activities	25,327	(2,346)
Increase (decrease) in cash	(320)	(3,133)
Cash at beginning of year	1,690	3,641
Cash at end of period	$ 1,370	$ 508

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 Paid-In	Retained	Treasury	Unamortized Restricted Stock	Accumulated Other Comprehensive	
	Shares	Amount	Capital	Earnings	Stock	Awards	Income (Loss)	Total
				(in thousands)				
Balance at December 31, 2002	27,738	$ 2,774	$ 19,130	$ 197,988	$ (19,981)	$ (5,065)	$ (17,358)	$ 177,488
Comprehensive income:								
Net income	-	-	-	34,046	-	-	-	34,046
Change in value of derivatives	-	-	-	-	-	-	4,136	4,136
Total comprehensive income	-	-	-	-	-	-	-	38,182
Issuance of common stock	9,488	949	102,136	-	-	-	-	103,085
Exercise of stock options	-	-	(146)	-	1,732	-	-	1,586
Issuance of restricted stock	-	-	10	-	53	(63)	-	-
Amortization of restricted stock	-	-	-	-	-	1,303	-	1,303
Balance at September 30, 2003	37,226	$ 3,723	$ 121,130	$ 232,034	$ (18,196)	$ (3,825)	$ (13,222)	$ 321,644

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the three months ended September 30,		For the nine months ended September 30,	
	2003	2002	2003	2002
	(in thousands)		(in thousands)	
Balance, beginning of period	$ (26,299)	$ (6,354)	$ (17,358)	$ 5,763
Current period reclassification to earnings	4,080	(439)	21,043	217
Current period change in derivative instruments	8,997	(3,001)	(16,907)	(15,774)
Balance, end of period	$ (13,222)	$ (9,794)	$ (13,222)	$ (9,794)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
September 30, 2003

(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, 2002 (the "2002 Annual Report on Form 10-K").

(2) ISSUANCE OF COMMON STOCK

In the first quarter of 2003, the Company completed the sale of 9,487,500 shares of its common stock under a registration statement filed with the Securities and Exchange Commission in December 2002. Aggregate net proceeds from the equity offering of $103.1 million were used to pay outstanding borrowings under the Company's revolving credit facility. The Company is reborrowing the repaid amounts under the credit facility as necessary to fund the acceleration of the development of the Company's Overton Field in East Texas and for general corporate purposes.

(3) GAS AND OIL PROPERTIES

The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits, and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company's unamortized costs of natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company's unamortized costs in natural gas and oil properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. At September 30, 2003, the Company's net book value of natural gas and oil properties did not exceed the ceiling amount. Decreases in market prices from September 30, 2003 levels, as well as changes in production rates, levels of reserves, and the evaluation of costs excluded from amortization, could result in future ceiling test impairments.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141), and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142), were issued in June 2001 and became effective for the Company on July 1, 2001, and January 1, 2002, respectively. The Company understands the majority of the oil and natural gas industry did not change its accounting and disclosures for mineral interest use rights (leasehold acquisition costs) upon the implementation of FAS 141 and 142. However, an interpretation of FAS

141 and 142 is being considered as to whether mineral interest use rights in gas and oil properties are intangible assets. Under this interpretation mineral interest use rights for both undeveloped and developed leaseholds would be classified as intangible assets, separate from gas and oil properties. The classification as an intangible asset would not affect how these items are accounted for under the full cost method of accounting with respect to the calculation of depreciation, depletion and amortization or the calculation of the ceiling test of gas and oil properties. At September 30, 2003, the Company had undeveloped leasehold of approximately $10.0 million that would be classified as "intangible undeveloped leasehold" if this interpretation were applied. Southwestern also had developed leasehold of approximately $8.1 million that would be classified as "intangible developed leasehold" if it applied the interpretation currently being considered. The portion of developed leasehold that would be reclassified represents the costs of developed leaseholds acquired or transferred to the full cost pool subsequent to June 30, 2001, the effective date of FAS 141. Additionally, FAS 142 requires that certain disclosures be made for all intangible assets. The Company has not made the disclosures set forth under FAS 142 related to the use rights of mineral interests.

Southwestern will continue to classify the use rights of mineral interests in gas and oil properties until further guidance is provided.

(4) 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 shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock. Options for 944,834 shares, with an average exercise price of $13.67 per share at September 30, 2002, were not included in the calculation of diluted shares because they would have had an antidilutive effect.

(5) DEBT

Debt balances as of September 30, 2003 and December 31, 2002 consisted of the following:

	September 30, 2003	December 31, 2002
	(in thousands)	
Senior notes:		
6.70% Series due 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 (2.63% at September 30, 2003 and 2.89% at December 31, 2002) unsecured revolving credit arrangements	37,000	117,400
Total debt	$ 262,000	$ 342,400

At September 30, 2003, the Company's revolving credit facility had a balance of $37.0 million and was classified as short-term debt in the Company's balance sheet. The Company's revolving credit facility has a capacity of $125 million and a three-year term that expires in July 2004. The Company intends to renew or replace its revolving credit facility prior to the July 2004 expiration date. The interest rate on the facility is 150 basis points over the current London Interbank Offered Rate (LIBOR). The 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 65% 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 at least 4.00 or higher through December 31, 2003. These covenants change over the term of the credit facility and generally become more restrictive. Additionally, the Company is precluded from paying dividends on its common stock under the revolving credit agreement. The Company has also entered into interest rate swaps for calendar year 2003 that require the Company to pay a fixed interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of its outstanding revolving debt. As a result of the reduced level of borrowings under the revolving credit facility during 2003, these interest rate swaps no longer qualify as cash flow hedges and therefore $0.3 million has been expensed in the accompanying financial statements for the first nine months of 2003.

(6) DERIVATIVE AND HEDGING ACTIVITIES

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149, was adopted by the Company on January 1, 2001. SFAS No. 133 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 September 30, 2003, the Company's net liability related to its cash flow hedges was $18.3 million. Additionally, at September 30, 2003, the Company had recorded a net of tax cumulative loss to other comprehensive income (equity section of the balance sheet) of $9.9 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. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the adoption of SFAS No. 133.

(7) SEGMENT INFORMATION

The Company applies SFAS 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 "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 September 30, 2003:					
Revenues from external customers	$ 41,913	$ 16,050	$ 10,114	$ 2,991[1]	$ 71,068
Intersegment revenues	4,964	19	45,425	112	50,520
Operating income (loss)	22,295	(3,420)	799	3,033	22,707
Depreciation, depletion and amortization expense	13,307	1,554	12	23	14,896
Interest expense [2]	2,760	1,198	11	248	4,217
Provision (benefit) for income taxes [2]	7,228	(1,760)	299	900	6,667
Assets	639,776	155,708	15,472	27,496[3]	838,452[3]
Capital expenditures	45,898[4]	1,731	1	180	47,810[4]
Three months ended September 30, 2002:					
Revenues from external customers	$ 28,024	$ 13,050	$ 10,017	$ --	$ 51,091
Intersegment revenues	2,301	13	23,619	112	26,045
Operating income (loss)	9,705	(2,243)	458	74	7,994
Depreciation, depletion and amortization expense	11,851	1,431	17	24	13,323
Interest expense [2]	4,354	847	--	232	5,433
Provision (benefit) for income taxes [2]	1,902	(1,219)	184	(70)	797
Assets	552,098	147,954	11,309	26,449[3]	737,810[3]
Capital expenditures	25,559	1,450	1	45	27,055
Nine months ended September 30, 2003:					
Revenues from external customers	$ 104,733	$ 94,099	$ 34,387	$ 2,991[1]	$ 236,210
Intersegment revenues	25,369	114	118,969	336	144,788
Operating income	62,708	2,477	2,026	3,116	70,327
Depreciation, depletion and amortization expense	36,238	4,622	36	69	40,965
Interest expense [2]	9,032	3,271	13	759	13,075
Provision (benefit) for income taxes [2]	19,689	(351)	765	1,288	21,391
Assets	639,776	155,708	15,472	27,496[3]	838,452[3]
Capital expenditures	121,130[4]	6,671	3	474	128,278[4]
Nine months ended September 30, 2002:					
Revenues from external customers	$ 78,503	$ 78,302	$ 31,948	$ --	$ 188,753
Intersegment revenues	11,658	101	66,324	336	78,419
Operating income	27,098	4,702	1,742	191	33,733
Depreciation, depletion and amortization expense	36,379	4,560	51	71	41,061
Interest expense [2]	12,887	2,582	--	670	16,139
Provision (benefit) for income taxes [2]	5,032	729	678	(330)	6,109
Assets	552,098	147,954	11,309	26,449[3]	737,810[3]
Capital expenditures	63,394	4,210	3	222	67,829

(1) Other revenues from external customers in 2003 resulted from the sale of real estate and certain fixed assets.
(2) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense (benefit) are incurred at the corporate level.
(3) 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.
(4) Exploration and Production capital expenditures for 2003 include $6.6 million of accrued, non-cash expenditures.

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.

(8) INTEREST AND INCOME TAXES PAID

The following table provides interest and income taxes paid during each period presented. Interest payments include amounts paid or received for the settlement of interest rate hedges.

	For the nine months ended September 30,	
	2003	2002
	(in thousands)	
Interest payments	$9,292	$12,243
Income tax payments	$ --	$ --

(9) MINORITY INTEREST IN PARTNERSHIP

In 2001, the Company's subsidiary, Southwestern Energy Production Company (SEPCO) formed a limited partnership, Overton Partners, L.P., with an investor to drill and complete 14 development wells in SEPCO's Overton Field located in Smith County, Texas. Because SEPCO is the sole general partner and owns a majority interest in the partnership, the operating and financial results are consolidated with the Company's exploration and production results and the investor's share of the partnership activity is reported as a minority interest item in the financial statements.

(10) 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 September 30, 2003 and December 31, 2002, the principal outstanding for these notes was $70.0 million and $71.0 million, respectively. 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 which is not funded by operations of the pipeline. As a result of the integration of NOARK Pipeline with the Ozark Gas Transmission System, management of the Company believes that it will realize its investment in NOARK over the life of the system. Therefore, no provision for any loss has been made in the accompanying financial statements. Additionally, the Company's gas distribution subsidiary has transportation contracts for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system. These contracts have expired and are on renewable year-to-year terms until terminated by 180 days' notice.

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 have arisen 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.

(11) ASSET RETIREMENT OBLIGATIONS

Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) was adopted by the Company on January 1, 2003. SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends FASB Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 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. Associated with the adoption of the standard, the Company increased current and long-term liabilities by $1.2 million and $5.5 million, respectively, net property and equipment by $5.3 million, net deferred tax assets by $0.5 million, and recorded an expense of $0.9 million constituting the cumulative effect of adoption. As of September 30, 2003, the Company had $0.8 million of current liabilities and $6.4 million of long-term liabilities associated with its asset retirement obligations. The new standard had no material impact on income before the cumulative effect of adoption in the three- and nine-month periods ended September 30, 2003, nor would it have had a material impact, on a pro forma basis, in the corresponding periods of 2002 assuming that this accounting standard had been adopted at such time.

(12) ACCOUNTING FOR STOCK-BASED COMPENSATION

The Company's stock-based employee compensation plan 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 FASB Statement No. 123, "Accounting for Stock-Based Compensation," to stock-based employee compensation.

	For the three months ended September 30,		For the nine months ended September 30,	
	2003	2002	2003	2002
	(in thousands, except per share)			
Net income, as reported	$10,878	$1,274	$34,046	$9,759
Add back: Amortization of restricted stock	436	314	1,303	939
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(718)	(569)	(2,149)	(1,702)
Pro forma net income	$10,596	$1,019	$33,200	$8,996
Earnings per share:				
Basic-as reported	$0.31	$0.05	$1.04	$0.39
Basic-pro forma	0.30	0.04	1.01	0.36
Diluted-as reported	0.30	0.05	1.01	0.37
Diluted-pro forma	0.29	0.04	0.99	0.35

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions for all periods presented: no dividend yield; expected volatility of 45.6%; risk-free interest rate of 3.4%; and expected lives of 6 years for all option grants. There were no options granted in the first nine months of 2003. The fair value of the options granted in the first nine months of 2002 was $0.2 million.

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

The following updates information as to the Company's financial condition provided in our 2002 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2003, and the comparable periods of 2002. 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 2002 Annual Report on Form 10-K.

OVERVIEW

We operate in three segments: Exploration and Production, Natural Gas Distribution and Marketing, Transportation and Other. Our financial results depend on a number of factors, in particular natural gas and oil prices, 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. 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, that we cannot control or predict.

We reported net income of $10.9 million, or $.30 per share on a fully diluted basis, on revenues of $71.1 million for the three months ended September 30, 2003, compared to net income of $1.3 million, or $0.05 per share, on revenues of $51.1 million for the same period in 2002. Included in our 2003 third quarter results were pre-tax gains of $3.0 million, or $.05 of diluted earnings per share, from the sale of real estate and certain fixed assets. Net income for the nine months ended September 30, 2003 was $34.0 million, or $1.01 per share on a diluted basis, on revenues of $236.2 million, compared to net income of $9.8 million, or $0.37 per share, on revenues of $188.8 million for the same period in 2002. The increase in revenues and earnings primarily resulted from higher natural gas prices experienced by our exploration and production segment.

<u>RESULTS OF OPERATIONS</u>

Exploration and Production

Our exploration and production segment's revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that gas and oil prices will not be subject to wide fluctuations in the future. Gas and oil prices affect the amount of cash flow available for capital expenditures, our ability to borrow and raise additional capital and the amount of gas and oil we can economically produce. We use hedging transactions with respect to a portion of our gas and oil production to achieve more predictable cash flows and to reduce our exposure to price fluctuations. Our future success depends on our ability to find, develop and acquire gas and oil reserves that are economically recoverable.

	For the three months ended September 30,		For the nine months ended September 30,	
	2003	2002	2003	2002
Revenues (in thousands)	$46,877	$30,325	$130,102	$90,161
Operating income (in thousands)	$22,295	$9,705	$62,708	$27,098
Gas production (MMcf)	10,241	8,971	27,601	27,330
Oil production (MBbls)	136	165	400	543
Total production (MMcfe)	11,053	9,961	29,999	30,588
Average gas price per Mcf	$4.23	$2.96	$4.22	$2.89
Average oil price per Bbl	$26.46	$22.65	$27.17	$20.87
Average unit costs per Mcfe				
Lease operating expenses	$0.43	$0.48	$0.40	$0.43
General & administrative expenses	$0.37	$0.25	$0.40	$0.27
Taxes, other than income taxes	$0.22	$0.15	$0.24	$0.17
Full cost pool amortization	$1.17	$1.16	$1.17	$1.16

Revenues, Operating Income and Production

Revenues. Revenues for our exploration and production segment were up 55% and 44% for the three- and nine-month periods ended September 30, 2003, respectively, both as compared to the same periods in 2002. The increases were primarily due to higher gas and oil prices received for our production.

Operating Income. Operating income for the exploration and production segment was up 130% for the three months ended September 30, 2003, and up 131% for the first nine months of 2003, both as compared to the same periods in 2002. The increases in operating income resulted from the increases in revenues, partially offset by increased general and administrative expenses and increased taxes other than income taxes.

Production. Gas and oil production during the third quarter of 2003 was 11.1 billion cubic feet (Bcf) equivalent, up from 10.1 Bcf equivalent in the second quarter of 2003 and 10.0 Bcf equivalent in the third quarter of 2002. The comparative increase in third quarter production resulted from an increase in production from the Overton Field in East Texas due to the accelerated development of the field, partially offset by declines experienced in our South Louisiana properties that began in the last half of 2002, combined with the loss of production resulting from the November 2002 sale of our Mid-Continent properties. Gas and oil production was 30.0 Bcf equivalent for the first nine months of 2003, compared to 30.6 Bcf equivalent for the first nine months of 2002. Gas production was 10.2 Bcf for the third quarter of 2003 compared to 9.0 Bcf for the third quarter of 2002. Gas production was 27.6 Bcf for the first nine months of 2003 compared to 27.3 Bcf for the same period of 2002. We sold 4.4 Bcf to our gas distribution systems during the nine months ended September 30, 2003, compared to 3.9 Bcf for the same period in 2002. Our oil production was 136 thousand barrels (MBbls) during the third quarter of 2003 and 400 MBbls for the first nine months of 2003, down from 165 MBbls and 543 MBbls for the same periods of 2002, respectively, due primarily to the loss of production from the Mid-Continent properties sold in 2002.

Commodity Prices

We received an average price of $4.23 per thousand cubic feet (Mcf) for our gas production for the three months ended September 30, 2003, up from $2.96 per Mcf for the same period of 2002. For the first nine months of 2003, we received an average gas price of $4.22 compared to $2.89 for the same period of 2002. We hedged 22.9 Bcf of gas production in the first nine months of 2003 through fixed-price swaps and zero-cost collars which had the effect of decreasing our average gas price realized during the period by $1.18 per Mcf. On a comparative basis, the average price realized during the first nine months of 2002 included the effect of hedges that increased our average price by $0.02 per Mcf.

For the remainder of 2003, we have 4.5 Bcf of gas production hedged with collars having an average NYMEX floor price of $3.30 per Mcf and an average NYMEX ceiling price of $5.07 per Mcf. We also have 3.0 Bcf of gas production for the remainder of 2003 hedged with fixed-price swaps at an average NYMEX price of $3.44 per Mcf. For 2004 and 2005, we have 29.2 Bcf and 3.0 Bcf, respectively, hedged under zero-cost collars and fixed-price swaps. See Part I, Item 3 of this Form 10-Q for additional information regarding the Company's commodity price risk hedging activities.

We received an average price of $27.17 per barrel for our oil production during the nine months ended September 30, 2003, up from $20.87 per barrel for the same period of 2002. The average price we received for our oil production in the first nine months of 2003 and 2002 was reduced by $2.64 per barrel and $2.43 per barrel, respectively, due to the effects of fixed-price swaps. For the remainder of 2003, we have a hedge on 90,000 barrels at an average NYMEX price of $26.73 per barrel. For 2004, we have 120,000 barrels hedged at an average price of $27.24 per barrel.

Operating Costs and Expenses

Lease operating expenses per Mcfe for this business segment were $0.43 for the third quarter of 2003, compared to $0.48 for the same period in 2002. Lease operating expenses per unit have decreased in 2003 as a larger portion of our production is being provided from the Overton Field which has lower operating costs. Taxes other than income taxes per Mcfe were $0.22 for the third quarter of 2003, compared to $0.15 for the same period in 2002. Severance taxes per Mcfe increased during the quarter due to higher average prices received for our production. General and administrative expenses per Mcfe were $0.37 and $0.40 for the third quarter and first nine months of 2003, respectively, compared to $0.25 and $0.27 for the same two comparable periods of 2002, respectively. The increase in general and administrative expenses in 2003 was due primarily to increased pension and insurance costs and the quarterly accrual of annual incentive compensation costs.

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 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 gas and oil prices may subsequently increase the ceiling. Our full cost ceiling is evaluated at the end of each quarter. At September 30, 2003, our unamortized costs of gas and oil properties did not exceed this ceiling amount. Natural gas and crude oil pricing has historically been unpredictable and any significant decline in gas and oil prices from current 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

The operating results of our gas distribution segment are highly seasonal. This segment typically realizes operating income during the winter heating season in the first and fourth quarters and operating losses in the second and third quarters of the year. The extent and duration of heating weather also impacts the profitability of this segment, although there is a weather normalization clause in our rates intended to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The gas distribution segment's profitability is also dependent upon the timing and amount of regulatory rate increases that are filed with and approved by the Arkansas Public Service Commission (APSC). For periods subsequent to allowed rate increases, our profitability is impacted by our ability to manage and control this segment's operating costs and expenses.

	For the three months ended September 30,		For the nine months ended September 30,	
	2003	2002	2003	2002
Revenues (in thousands)	$16,069	$13,063	$94,213	$78,403
Gas purchases (in thousands)	$8,448	$5,490	$58,082	$43,408
Operating costs and expenses (in thousands)	$11,041	$9,816	$33,654	$30,293
Operating income (loss) (in thousands)	$(3,420)	$(2,243)	$2,477	$4,702
Deliveries (Bcf)				
Sales and end-use transportation	3.1	3.2	17.6	17.2
Off-system transportation	--	1.3	0.1	2.0
Average number of customers	137,123	134,807	138,782	136,456
Average sales rate per Mcf	$11.00	$8.39	$7.77	$6.57
Heating weather - degree days	43	14	2,597	2,291
- percent of normal	102%	--	104%	91%

Revenues and Operating Income

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- and nine-month periods ended September 30, 2003 increased 23% and 20%, respectively, from the comparable periods of 2002 due primarily to increases in the cost of gas supplies that resulted from higher gas prices.

Operating Income. Operating income of our gas distribution segment decreased $1.2 million in the third quarter of 2003 and decreased $2.2 million in the first nine months of 2003, as compared to the same periods of 2002. The decreases were primarily due to increased operating costs and expenses. Weather during the first nine months of 2003 was 4% colder than normal and 13% colder than the same period of 2002. The weather normalization clause in the utility's rates is intended to lessen the impacts of revenue increases and decreases that might result from weather variations during the winter heating season.

Our gas distribution subsidiary, Arkansas Western Gas Company (AWG), filed an application with the APSC on November 8, 2002, for a rate increase of $11.0 million annually. In the third quarter of 2003 we received regulatory approval from the APSC of a rate increase totaling $4.1 million annually, exclusive of costs to be recovered through AWG's purchase gas adjustment clause. The order also entitled AWG to recover certain additional costs totaling $2.3 million through its purchase gas adjustment clause over a two-year period. In its order, the Commission approved the general terms of a Joint Stipulation and Settlement Agreement between AWG, the Staff of the APSC and various other consumer groups that was filed on July 17, 2003, but made certain modifications which included reducing the recovery of certain additional costs from $2.9 million to $2.3 million. The rate increase is effective for all customer bills rendered on or after October 1, 2003. AWG's last rate increase was approved in December 1996 for its Northwest region and in December 1997 for its Northeast region. The Attorney General for the State of Arkansas has filed a request for a rehearing with the APSC on certain issues that could impact the collection of the $2.3 million of additional costs to be collected through AWG's purchased gas adjustment clause. We have also filed a request for a rehearing on certain issues that could impact the rate increase and the timing of the implementation of the increased rates. The APSC has not yet ruled on the requests for a rehearing.

The difference between the $11.0 million rate adjustment requested by AWG and the rate adjustment contained in the approved order primarily results from a reduction in AWG's requested return on equity and a change in AWG's assumed capital structure. In the rate increase request that was filed with the APSC, we assumed an allowed return on equity of 12.9% and a capital structure of 48% debt and 52% equity. The final order provides for an allowed return on equity of 9.9% and an assumed capital structure of 52% debt and 48% equity. The 9.9% equity return is in line with the equity return approved in recent settlements that have been approved for the other two Arkansas local gas distribution companies.

Deliveries and Rates

The utility systems delivered 3.1 Bcf and 17.6 Bcf to sales and end-use transportation customers during the three- and nine-month periods ended September 30, 2003, compared to 3.2 Bcf and 17.2 Bcf for the same periods in 2002. The increase in deliveries during the first nine months of 2003 was primarily due to the effects of colder weather. The increase in gas costs in the first nine months of 2003 was reflected in the utility segment's average rate for its sales which increased to $7.77 per Mcf, up from $6.57 per Mcf for the same period in 2002. Costs paid for purchases of natural gas are passed through to customers under automatic adjustment clauses. Our utility segment hedged 2.7 Bcf of gas purchases in the first nine months of 2003 decreasing its total gas supply cost by $7.5 million. In the first nine months of 2002, 3.3 Bcf of gas purchase hedges increased the total gas supply cost by $6.4 million. As of September 30, 2003, we have hedges in place on 5.1 Bcf of future gas supply purchases for the months of November 2003 through March 2004 at an average fixed cost of $5.38 per Mcf.

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 intercompany versus third-party sources. Other operating costs and expenses for this segment during the third quarter and nine months ended September 30, 2003 were higher than the comparable periods of the prior year due primarily to increased general and administrative expenses and increased transmission costs. The increase in general and administrative expense primarily resulted from increased pension and insurance costs and the quarterly accrual of annual incentive compensation costs. Increased transmission costs resulted from higher fuel costs.

Marketing, Transportation and Other

Operating income from the marketing, transportation and other segment, which includes income from real property held by our subsidiary, A.W. Realty Company, was $3.8 million for the third quarter of 2003 and $5.1 million for the first nine months of 2003, up from $0.5 million and $1.9 million, respectively, for the same periods of 2002. The results for 2003 include a gain of $3.0 million recorded in other operating revenues that was recognized from the sale of real estate and certain fixed assets.

Marketing

	For the three months ended September 30,		For the nine months ended September 30,	
	2003	2002	2003	2002
Marketing revenues (in thousands)	$55,539	$33,636	$153,356	$98,272
Marketing operating income (in thousands)	$799	$458	$2,026	$1,742
Gas volumes marketed (Bcf)	12.2	11.6	30.9	36.2

The increase in our gas marketing revenues for the three- and nine-month periods ended September 30, 2003 relates to a significant increase in natural gas commodity prices from the prior year and was offset by a comparable increase in purchased gas costs. Operating income for this segment was $0.8 million and $2.0 million for the three- and nine-month periods ended September 30, 2003, compared to $0.5 million and $1.7 million, respectively, for the same periods in 2002. We marketed 12.2 Bcf of gas in the third quarter and 30.9 Bcf in the first nine months of 2003, compared to 11.6 Bcf and 36.2 Bcf, respectively, for the same periods in 2002. The decrease in volumes marketed year-to-date, as compared to the same period in 2002, primarily resulted from lower volumes marketed for third parties due to our continuing effort to reduce credit risk.

Transportation

Our share of the NOARK Pipeline System Limited Partnership (NOARK) pretax results of operations included in other income was a gain of $1.0 million for the first nine months of 2003, compared to a loss of $0.4 million for the same period in 2002. The gain in the first nine months of 2003 resulted primarily from a gain of $1.3 million recognized by the Company on the sale of a 28-mile portion of NOARK's pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million.

Interest Expense

Interest expense decreased 22% for the third quarter of 2003 and 19% for the first nine months of 2003, both as compared to the same periods in 2002, due to lower average borrowings, a lower average interest rate, and increased capitalized interest. Our average borrowings decreased as net proceeds of $103.1 million from the Company's equity offering in the first quarter of 2003 were initially used to pay down the Company's revolving credit facility. The Company is reborrowing the repaid amounts under the credit facility as necessary to fund the acceleration of the development of the Company's Overton Field in East Texas and for general corporate purposes. Interest is capitalized in the exploration and production segment on costs that are unevaluated and excluded from amortization.

Income Taxes

The effective tax rate for the nine months ended September 30, 2003 was 38.0% compared to 38.5% for the same period in 2002. The changes in the provision for deferred income taxes recorded in the nine months ended September 30, 2003, as compared to the same period in 2002, resulted primarily from the increase in the level of pre-tax income in 2003. Also impacting deferred taxes is the deduction of intangible drilling costs in the year incurred for tax purposes, netted against the turnaround of intangible drilling costs deducted for tax purposes in prior years. Intangible drilling costs are capitalized and amortized over future years for financial reporting purposes under the full cost method of accounting.

Adoption of Accounting Principle

Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) was adopted by the Company on January 1, 2003. SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends FASB Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 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 effect of this standard on the Company's results of operations and financial condition at adoption was an increase in current and long-term liabilities of $1.2 million and $5.5 million, respectively; a net increase in property, plant and equipment of $5.3 million; a cumulative effect of adoption expense of $0.9 million and a deferred tax asset of $0.5 million. As of September 30, 2003, the Company had $0.8 million of current liabilities and $6.4 million of long-term liabilities associated with its asset retirement obligations. Subsequent to adoption, the Company does not expect this standard to have a material impact on the Company's financial position or its results of operations.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds and our revolving line of credit (discussed below under "Financing Requirements") as our primary sources of liquidity. We may borrow up to $125.0 million under our revolving credit facility from time to time. During the first quarter of 2003, we completed the sale of 9,487,500 shares of our common stock under a registration statement filed with the Securities and Exchange Commission in December 2002. Aggregate net proceeds from the equity offering of $103.1 million were used to repay borrowings under our credit facility. We are reborrowing the repaid amounts as necessary to fund the acceleration of the development of our Overton Field in East Texas and for general corporate purposes. As of September 30, 2003, the Company's revolving credit facility had a balance of $37.0 million and was classified as short-term debt in the Company's balance sheet. We expect our capital expenditures (discussed below under "Capital Expenditures") for 2003 to be funded by the cash flow generated by our operations and the funds that may be available under our credit facility.

Net cash provided by operating activities was $94.9 million in the first nine months of 2003, compared to $68.4 million for the same period of 2002. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. Historically, our capital expenditures have predominantly been funded through cash provided by operations. For the first nine months of 2003, cash provided by operating activities provided 78% of these requirements. For the same period of 2002, cash provided by operating activities exceeded these requirements.

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 "Quantitative and Qualitative Disclosures About Market Risks" and Note 6 to the financial statements. 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 nine months of 2003 were $128.3 million, including $6.6 million of accrued, non-cash expenditures, compared to $67.8 million for the same period in 2002. Capital investments during calendar year 2003 are currently expected to be approximately $173.6 million compared to $92.1 million in 2002. Our 2003 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 future capital investments dependent upon the level of cash flow generated from operations.

Off-Balance Sheet Arrangements

We hold a 25% general partnership interest in NOARK and 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. This debt financed a portion of the original cost to construct the NOARK Pipeline. Our share of the guarantee is 60%. At September 30, 2003, the outstanding principal amount of these notes was $70.0 million and our share of the guarantee was $42.0 million. The notes were issued in June 1998 and 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 nine months of 2003 and do not expect to advance any funds during the remainder of 2003.

Our share of the results of operations included in other income related to our NOARK investment was a gain of $1.0 million for the first nine months of 2003, compared to a loss of $0.4 million for the same period in 2002. The gain in the first nine months of 2003 resulted primarily from NOARK’s sale of a 28-mile portion of its pipeline located in Oklahoma that had limited strategic value to the overall system. Sales proceeds to NOARK were $10.0 million and our share of the proceeds was $2.5 million. We believe that we will be able to continue to reduce the losses we have experienced on the NOARK project and expect our investment in NOARK to be realized over the life of the system.

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 September 30, 2003 are 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)		
Debt	$ 262,000	$ 37,000	$ 125,000	$ -	$ 100,000
Operating leases[1]	6,075	1,158	2,196	899	1,822
Unconditional purchase obligations[2]	-	-	-	-	-
Demand charges[3]	25,726	11,261	7,029	3,060	4,376
Other obligations[4]	2,575	2,475	50	50	-
	$296,376	$51,894	$134,275	$ 4,009	$106,198

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

(2) Our utility segment has volumetric commitments for the purchase of gas under competitive bid packages and wellhead contracts. Volumetric purchase commitments at September 30, 2003 totaled 2.8 Bcf, comprised of 1.3 Bcf in less than one year, 1.0 Bcf in one to three years, 0.3 Bcf in three to five years and 0.2 Bcf in more than five years. Our volumetric purchase commitments are priced 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 $18.8 million of demand charges on 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 $6.9 million of demand transportation charges.

(4) Our significant other obligations include approximately $0.4 million of land leases, approximately $0.8 million for drilling rig commitments and approximately $1.3 million of various information technology support and data subscription agreements.

We refer you to "Financing Requirements" below for a discussion of the terms of our long-term debt.

Contingent Liabilities or Commitments

We have the following commitments and contingencies that could create, increase or accelerate our liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Our return on the assets of these plans in 2002 was negative which, combined with other factors, has resulted in an increase in pension expense and our required funding of the plans for 2003. As a result of actuarial data, we expect to record pension expense of approximately $3.4 million in 2003, of which $2.5 million has been recorded in the first nine months of 2003.

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 September 30, 2003 the principal outstanding for these notes was $70.0 million and our share of the guarantee was $42.0 million. The notes require semi-annual principal payments of $1.0 million.

Financing Requirements

Our total debt outstanding was $262.0 million at September 30, 2003 and $342.4 million at December 31, 2002. Of the total outstanding at September 30, 2003, $37.0 million was outstanding under our revolving credit facility and was classified as short-term in our balance sheet. The revolving credit facility has a current capacity of $125.0 million and expires in July 2004. We intend to renew or replace our revolving credit facility prior to the July 2004 expiration date.

The interest rate on the current facility is 150 basis points over the current LIBOR. The credit facility contains covenants which impose certain restrictions on us. Under the credit agreement, we may not issue total debt in excess of 65% of our total capital, we must maintain a certain level of shareholders' equity, and we must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 4.00 or higher through December 31, 2003. These covenants change over the term of the credit facility and generally become more restrictive. Additionally, we are precluded from paying dividends on our common stock under the revolving credit agreement. We have also entered into interest rate swaps for calendar year 2003 that require us to pay a fixed interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of our outstanding revolving debt. As a result of the reduced level of borrowings under the revolving credit facility during 2003, these interest rate swaps no longer qualify as cash flow hedges and therefore $0.3 million has been expensed in the accompanying financial statements.

During the first nine months of 2003, our total debt decreased by $80.4 million primarily due to the initial use of the net proceeds from the issuance of common stock to pay off the balance of our revolving debt. We are reborrowing the repaid amounts as necessary to fund the acceleration of the development drilling of our Overton Field properties in East Texas and for general corporate purposes as these costs are incurred. Total debt at September 30, 2003, accounted for 45% of our total capitalization.

At September 30, 2003, the NOARK partnership had outstanding debt totaling $70.0 million. We and the other general partner of NOARK have severally guaranteed the principal and interest payments on the NOARK debt. Our share of the several guarantee is 60%.

Working Capital

We maintain access to funds that may be needed to meet seasonal requirements through our revolving credit facility described above. We had negative working capital of $36.1 million at September 30, 2003, compared to positive working capital of $1.6 million at December 31, 2002. The negative working capital at September 30, 2003 is due to our revolving debt balance of $37.0 million which is currently classified as short-term. The balance outstanding under our revolving credit facility will remain as a current liability until the current revolving credit facility is replaced with a new long-term facility. We intend to renew or replace our revolving credit facility prior to its July 2004 expiration date. Current assets increased by 5% in the first nine months of 2003 while current liabilities increased 55%. Current liabilities would have increased 6% without consideration of the current classification of revolving debt. The increase in current assets during the first nine months of 2003 was due primarily to a $4.8 million increase in current gas stored underground, partially offset by a decrease in accounts receivable caused by seasonal deliveries of our gas distribution segment. The increase in current liabilities during the first nine months of 2003, without consideration of the increase that resulted from the classification of revolving debt, was due to increases in accounts payable and interest payable due to the timing of payments, partially offset by decreases related to our hedging activities and our over-recovered gas purchase costs. Under-recovered purchased gas costs for the Company's gas distribution segment were $2.1 million at September 30, 2003, compared to over-recovered costs of $5.7 million at December 31, 2002. Purchased gas costs are recovered from our utility customers in subsequent months through automatic cost of gas adjustment clauses included in the utility's filed rate tariffs. Changes in other current assets and current liabilities are primarily due to the timing of expenditures and receipts. At September 30, 2003, we had a current hedging liability of $16.2 million recorded as a result of the provisions of SFAS No. 133, compared to $20.4 million at December 31, 2002.

CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC on a quarterly basis. Under these rules, 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 plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Application of these rules during periods of relatively low natural gas or oil prices, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on September 30, 2003, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and is generally less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We engage the services of an independent petroleum consulting firm to review reserves as prepared by our reservoir engineers.

Statement of Financial Accounting Standards No. 141, "Business Combinations" (FAS 141), and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (FAS 142), were issued in June 2001 and became effective for us on July 1, 2001, and January 1, 2002, respectively. We understand the majority of the oil and natural gas industry did not change its accounting and disclosures for mineral interest use rights (leasehold acquisition costs) upon the implementation of FAS 141 and 142. However, an interpretation of FAS 141 and 142 is being considered as to whether mineral interest use rights in gas and oil properties are intangible assets. Under this interpretation, mineral interest use rights for both undeveloped and developed leaseholds would be classified as intangible assets, separate from gas and oil properties. The classification as an intangible asset would not affect how these items are accounted for under the full cost method of accounting with respect to the calculation of depreciation, depletion and amortization or the calculation of the ceiling test of our gas and oil properties. At September 30, 2003, we had undeveloped leasehold of approximately \$10.0 million that would be classified as "intangible undeveloped leasehold" if this interpretation were applied. We also had developed leasehold of approximately \$8.1 million that would be classified as "intangible developed leasehold" if we applied the interpretation currently being considered. The portion of developed leasehold that would be reclassified represents the costs of developed leaseholds acquired or transferred to the full cost pool subsequent to June 30, 2001, the effective date of FAS 141. Additionally, FAS 142 requires that certain disclosures be made for all intangible assets. We have not made the disclosures set forth under FAS 142 related to the use rights of mineral interests.

We will continue to classify the use rights of mineral interests in gas and oil properties until further guidance is provided.

Hedging

We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow, as well as to manage the price volatility of natural gas purchases in our gas distribution segment, due to fluctuations in the prices of natural gas and oil and in interest rates. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. 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.

Our derivative instruments are accounted for under SFAS No. 133 and are recorded at fair value in our financial statements. We utilize market-based quotes from our hedge counterparties to value these open positions. These valuations are recognized as assets or liabilities in our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production, gas marketing transactions or interest rates, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected in natural gas and oil sales or in gas purchases. Results of settled interest rate hedges are reflected in interest expense. Ineffective hedges, derivatives not qualifying for accounting treatment as hedges, or ineffective portions of hedges are recognized immediately in earnings. Future market price volatility could create significant changes to the hedge positions recorded in our financial statements. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" in this Form 10-Q for additional information regarding our hedging activities.

Regulated Utility Operations

Our utility operations are subject to the rate regulation and accounting requirements of the APSC. Allocations of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from those generally applied by non-regulated operations. Such allocations to meet regulatory accounting requirements are considered generally accepted accounting principles for regulated utilities provided that there is a demonstrated ability to recover any deferred costs in future rates.

During the ratemaking process, the regulatory commission may require a utility to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows the utility to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. This causes certain expenses to be deferred as a regulatory asset and amortized to expense as they are recovered through rates. The regulatory commission has not required any unbundling of services, although some business customers are free to contract for their own gas supply. There are no regulations relating to unbundling of services currently anticipated; however, should any such regulation be proposed and adopted, certain of these assets may no longer meet the criteria for deferred recognition and, accordingly, a write-off of regulatory assets and stranded costs could be required.

Pension Accounting

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation. Two of the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For 2002, the assumed discount rate was 6.8% and the assumed expected return was 9.0%.

Using the assumed rates discussed above, we recorded pension expense of $0.9 million in 2002 and a pension liability of $5.6 million at December 31, 2002. Assuming a 1% change in the 2002 rates (lower discount rate and lower rate of return), we would have recorded pension expense of $1.7 million in 2002, and recorded an accrued pension liability of $10.7 million at December 31, 2002.

For 2003, we expect our pension expense to be approximately $3.4 million using an assumed discount rate of 6.8% and an assumed expected return of 9.0%. Accordingly, pension expense of $2.5 million was recorded in the first nine months of 2003.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the exploration and production 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 10.4 Bcf at $3.37 at September 30, 2003 and 10.1 Bcf at $3.05 at December 31, 2002.

The gas in inventory for the exploration and production segment is used primarily to supplement 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 exploration and production 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. Declines in the future market price of natural gas could result in us writing down our carrying cost of gas in storage.

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;

- 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;
- changing market conditions and prices (including regional basis differentials);
- the comparative cost of alternative fuels;
- 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 set forth in our 2002 Annual Report on Form 10-K which are incorporated by reference herein.

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 incorporated by reference 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 RISKS

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. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The 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 Risks

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. 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. We have entered into interest rate swaps for calendar year 2003 that require us to pay an average fixed interest rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of our outstanding revolving debt. Our revolving debt was $117.4 million at December 31, 2002, and had an average interest rate of 3.23%. At September 30, 2003, we had a balance of $37.0 million that was classified as short-term debt in the Company's balance sheet. As a result of the reduced level of borrowings under the revolving credit facility during 2003, these interest rate swaps no longer qualify as cash flow hedges and therefore $0.3 million has been expensed in the accompanying financial statements.

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. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), the weighted average contract prices, and the total dollar contract amount by expected maturity dates. The "Carrying Amount" for the contract amounts is calculated as the contractual payments for the quantity of gas or oil to be exchanged under futures contracts and does not represent amounts recorded in our financial statements. The "Fair Value" represents values for the same contracts using comparable market prices at September 30, 2003. At September 30, 2003, the "Carrying Amount" exceeded the "Fair Value" of these financial instruments by $18.2 million.

	Expected Maturity Date					
	2003		2004		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Natural Gas Production and Marketing:						
Swaps with a fixed price receipt						
Contract volume (Bcf)	3.0		7.2		3.0	
Weighted average price per Mcf	$3.44		$4.01		$4.58	
Contract amount (in millions)	$10.3	$6.2	$28.9	$22.6	$13.8	$13.9
Basis swaps with a fixed price receipt						
Contract volume (Bcf)	1.5		1.5		-	
Weighted average price per Mcf	$0.09		$0.09		-	
Contract amount (in millions)	$0.1	$0.1	$0.2	$0.2	-	-
Swaps with a fixed price payment						
Contract volume (Bcf)	0.1		0.4	-		
Weighted average price per Mcf	$4.77		$5.06		-	
Contract amount (in millions)	$0.4	$0.4	$2.1	$2.0	-	-
Price collar						
Contract volume (Bcf)	4.5		22.0		-	
Weighted average floor price per Mcf	$3.30		$3.82		-	
Contract amount of floor (in millions)	$14.9	$14.9	$84.0	$88.5	-	-
Weighted average ceiling price per Mcf	$5.07		$6.26		-	
Contract amount of ceiling (in millions)	$22.9	$21.9	$137.8	$128.5	-	-

Oil Production:						
Swaps with a fixed price receipt						
Contract volume (MBbls)	90		120		-	
Weighted average price per Bbl	$26.73		$27.24		-	
Contract amount (in millions)	$2.4	$2.2	$3.3	$3.4	-	-
Natural Gas Purchases:						
Swaps with a fixed price payment						
Contract volume (Bcf)	1.7		3.4		-	
Weighted average price per Mcf	$5.38		$5.38		-	
Contract amount (in millions)	$9.2	$8.4	$18.4	$17.3	-	-

ITEM 4. CONTROLS AND PROCEDURES

As of the end of the period covered by the date of this report, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of our evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the disclosure controls and procedures were effective in all material respects to ensure that information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized and reported as and when required.

PART II
OTHER INFORMATION

Items 1 - 5.

No developments required to be reported under Items 1 - 5 occurred during the quarter ended September 30, 2003.

Item 6(a). 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) 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.

Item 6(b). Reports on Form 8-K

Date of Report	Item Number	Financial Statements Required to be Filed
October 8, 2003	7,9	No
October 8, 2003	7,9	No
September 23, 2003	7,9	No
September 18, 2003	5,7	No
September 16, 2003	7,9	No
September 5, 2003 (amendment of 8-K filed August 7, 2003)	7,9	No
August 8, 2003	7,9	No
July 29, 2003	7,12	No
July 17, 2003	5,7	No
July 9, 2003 (amendment of 8-K filed November 13, 2002)	7,9	No
July 9, 2003 (amendment of 8-K filed December 4, 2002)	7,9	No
July 9, 2003 (amendment of 8-K filed March 5, 2003)	7,9	No
July 9, 2003 (amendment of 8-K filed March 12, 2003)	7,9	No
July 9, 2003 (amendment of 8-K filed April 29, 2003)	7,9	No
July 9, 2003 (amendment of 8-K filed May 14, 2003)	7,9	No

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

DATE: October 30, 2003

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

Exhibit 31.1

CERTIFICATION

I, Harold M. Korell, Chief Executive Officer of Southwestern Energy Company, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southwestern Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2003

/s/ HAROLD M. KORELL
Harold M. Korell
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Greg D. Kerley, Chief Financial Officer of Southwestern Energy Company, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Southwestern Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2003

/s/ GREG D. KERLEY
Greg D. Kerley
Chief Financial Officer

Exhibit 32

CERTIFICATION
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of section 1350, chapter 63 of title 18, United States Code), each of the undersigned officers of Southwestern Energy Company, an Arkansas corporation (the "Company"), does hereby certify that:

> The Quarterly Report on Form 10-Q for the quarter ended September 30, 2003 (the "Form 10-Q") of the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: October 30, 2003

/s/ HAROLD M. KORELL
Harold M. Korell
Chief Executive Officer

Dated: October 30, 2003

/s/ GREG D. KERLEY
Greg D. Kerley
Chief Financial Officer