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, 2002**

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 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)

No Change
(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 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 21, 2002
Common Stock, Par Value $.10	25,724,259

PART I

FINANCIAL INFORMATION

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	September 30, 2002	December 31, 2001
	($ in thousands)	
Current Assets		
Cash	$ 508	$ 3,641
Accounts receivable	23,807	42,244
Inventories, at average cost	27,246	26,606
Hedging asset - SFAS No. 133	3,337	9,381
Regulatory asset - hedges	-	5,817
Other	3,155	4,996
Total current assets	58,053	92,685
Investments	15,138	15,538
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	1,033,898	970,680
Gas distribution systems	195,993	192,784
Gas in underground storage	33,118	32,046
Other	30,666	30,110
	1,293,675	1,225,620
Less: Accumulated depreciation, depletion and amortization	646,547	605,790
	647,128	619,830
Other Assets	17,491	19,408
Total Assets	$ 737,810	$ 747,461

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, 2002	December 31, 2001
	($ in thousands)	
Current Liabilities		
Accounts payable	24,417	41,644
Taxes payable	2,342	4,400
Interest payable	6,429	2,653
Customer deposits	4,790	4,845
Hedging liability - SFAS No. 133	13,876	6,990
Over-recovered purchased gas costs	5,071	8,184
Regulatory liability - hedges	2,978	-
Other	2,882	2,752
Total current liabilities	62,785	71,468
Long-Term Debt	353,200	350,000
Other Liabilities		
Deferred income taxes	118,577	122,381
Other	10,246	7,525
	128,823	129,906
Commitments and Contingencies		
Minority Interest in Partnership	12,818	13,001
Shareholders' Equity		
Common stock, $.10 par value; authorized 75,000,000 shares, issued 27,738,084 shares	2,774	2,774
Additional paid-in capital	19,059	19,764
Retained earnings	193,436	183,677
Accumulated other comprehensive income (loss)	(9,794)	5,763
	205,475	211,978
Less: Common stock in treasury, at cost, 2,013,825 shares in 2002 and 2,261,766 shares in 2001	22,434	25,196
Unamortized cost of 420,083 restricted shares in 2002 and 416,537 restricted shares in 2001 issued under stock incentive plans	2,857	3,696
	180,184	183,086
Total Liabilities and Shareholders' Equity	$ 737,810	$ 747,461

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

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

	Three Months Ended September 30, 2002	Three Months Ended September 30, 2001	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
	($ in thousands, except per share amounts)			
Operating Revenues				
Gas sales	$ 35,656	$ 41,975	$ 140,248	$ 189,533
Gas marketing	10,018	11,392	31,948	64,104
Oil sales	3,728	4,348	11,327	13,192
Gas transportation and other	1,689	1,681	5,230	5,719
	51,091	59,396	188,753	272,548
Operating Costs and Expenses				
Gas purchases - utility	3,198	4,119	31,770	54,617
Gas purchases - marketing	9,287	10,518	29,414	61,098
Operating expenses	9,698	9,379	28,292	28,693
General and administrative expenses	5,527	5,049	17,351	17,456
Depreciation, depletion and amortization	13,323	13,881	41,061	38,155
Taxes, other than income taxes	2,064	2,187	7,132	7,652
	43,097	45,133	155,020	207,671
Operating Income	7,994	14,263	33,733	64,877
Interest Expense				
Interest on long-term debt	5,510	5,787	16,209	18,558
Other interest charges	287	180	945	1,009
Interest capitalized	(364)	(375)	(1,015)	(1,235)
	5,433	5,592	16,139	18,332
Other Income (Expense)	(124)	(184)	(598)	(162)
Income Before Income Taxes & Minority Interest	2,437	8,487	16,996	46,383
Minority Interest in Partnership	(366)	(261)	(1,128)	(645)
Income Before Income Taxes	2,071	8,226	15,868	45,738
Income Tax Provision				
Current	-	-	-	-
Deferred	797	3,208	6,109	17,838
	797	3,208	6,109	17,838
Net Income	$ 1,274	$ 5,018	$ 9,759	$ 27,900
Basic Earnings Per Share	$0.05	$0.20	$0.39	$1.11
Basic Average Common Shares Outstanding	25,306,920	25,190,387	25,195,812	25,189,045
Diluted Earnings Per Share	$0.05	$0.20	$0.37	$1.09
Diluted Average Common Shares Outstanding	26,096,616	25,621,214	26,029,923	25,591,554

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

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

	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
	($ in thousands)	
Cash Flows From Operating Activities		
Net income	$ 9,759	$ 27,900
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	42,864	39,342
Deferred income taxes	6,109	17,838
Equity in loss of NOARK partnership	400	1,043
Minority interest in partnership	(183)	271
Change in assets and liabilities:		
Accounts receivable	19,121	49,056
Inventories	(640)	(9,112)
Under/over-recovered purchased gas costs	(3,113)	10,845
Accounts payable	(9,604)	(23,872)
Interest payable	3,775	4,070
Taxes payable	(2,058)	(1,955)
Other assets and liabilities	1,975	(769)
Net cash provided by operating activities	68,405	114,657
Cash Flows From Investing Activities		
Capital expenditures	(67,829)	(77,143)
Investment in NOARK partnership	-	(1,449)
Change in gas stored underground	(1,072)	(4,986)
Other items	(291)	484
Net cash used in investing activities	(69,192)	(83,094)
Cash Flows From Financing Activities		
Payments on revolving long-term debt	(144,400)	(201,000)
Borrowings under revolving long-term debt	147,600	161,300
Change in bank drafts outstanding	(7,623)	-
Proceeds from exercise of common stock options	2,077	69
Contributions from minority interest partner	-	6,355
Net cash used in financing activities	(2,346)	(33,276)
Decrease in cash	(3,133)	(1,713)
Cash at beginning of year	3,641	2,386
Cash at end of period	$ 508	$ 673

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001 *	2002	2001 *
	($ in thousands)		($ in thousands)	
Net income	$ 1,274	$ 5,018	$ 9,759	$ 27,900
Other comprehensive income (loss):				
Transition adjustment from adoption of SFAS No. 133	-	-	-	(36,963)
Change in value of derivative instruments	(3,440)	1,369	(15,557)	42,933
Comprehensive Income (Loss)	$ (2,166)	$ 6,387	$ (5,798)	$ 33,870

Reconciliation of Accumulated Other Comprehensive Income (Loss):

Balance, Beginning of Period	$ (6,354)	$ 4,601	$ 5,763	$ -
Cumulative effect of adoption of SFAS No. 133	-	-	-	(36,963)
Current period reclassification to earnings	(439)	(743)	217	21,634
Current period change in derivative instruments	(3,001)	2,112	(15,774)	21,299
Balance, End of Period	$ (9,794)	$ 5,970	$ (9,794)	$ 5,970

* The 2001 Consolidated Statements of Comprehensive Income were restated to correct the presentation of comprehensive income, as discussed in Footnote 1 to Consolidated Financial Statements.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2002

1. **BASIS OF PRESENTATION**

The financial statements included herein are unaudited; however, such financial statements reflect 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 accounting policies are summarized in the 2001 Annual Report on Form 10-K/A, Item 8, Notes to Consolidated Financial Statements. Certain reclassifications have been made to the prior year's financial statements to conform with the 2002 presentation. These reclassifications had no effect on previously reported net income.

In the second quarter of 2002, the Company corrected its presentation of comprehensive income for prior periods to properly reflect amounts associated with hedging activities. This correction in presentation of the nine months ended September 30, 2001 resulted in a comprehensive income decrease of $15.3 million. This correction had no effect on the Company's previously reported net income, earnings per share or cash flows, nor did it have any impact on the Company's balance sheet. The prior period corrections in the presentation of comprehensive income were reflected in amendments to the Company's filings on Form 10-K for the year ended December 31, 2001 and Form 10-Q for the three months ended March 31, 2002, both of which were filed in September 2002 in conjunction with the Company's change in auditors from Arthur Andersen LLP to PricewaterhouseCoopers LLP.

2. **OIL AND GAS PROPERTIES**

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas 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 oil and gas prices may subsequently increase the ceiling. At September 30, 2002, the Company's unamortized costs of oil and gas properties did not exceed this ceiling amount. The Company's full cost ceiling is evaluated at the end of each quarter. A 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.

3. EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each year. The average number of common shares outstanding is reduced for shares of restricted stock granted under the Company's incentive compensation plans that have not yet vested. 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 incremental shares of restricted stock assuming full vesting. The Company had options for 944,834 shares of common stock with a weighted average exercise price of $13.67 per share at September 30, 2002, and options for 997,700 shares with an average exercise price of $13.90 per share at September 30, 2001, that were not included in the calculation of diluted shares because they would have had an antidilutive effect.

4. LONG-TERM DEBT

In July 2001, the Company arranged an unsecured revolving credit facility with a group of banks that has a current capacity of $140 million and a three-year term. The interest rate on the current facility is 150 basis points over the current London Interbank Offered Rate (LIBOR), and was 4.6%, including the effects of interest rate swaps, at September 30, 2002. The interest rate increased 12.5 basis points in July 2002 as the result of a downgrade of the Company's public debt by Moody's. 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 70% of its total capital, must maintain a certain level of shareholders' equity, and the Company must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 3.75 or higher through December 31, 2002. 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. At September 30, 2002, the Company's revolving credit facility had a balance of $128.2 million and was classified as long-term debt in the Company's balance sheet. The Company has also entered into interest rate swaps for calendar year 2002 that allow the Company to pay a fixed interest rate of 4.9% (based upon current rates under the revolving credit facility) on $100.0 million of its outstanding revolving debt. Interest rate swaps entered into for 2003 will allow the Company to pay a fixed rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of its outstanding revolving debt.

5. DERIVATIVE AND HEDGING ACTIVITIES

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS No. 137 and SFAS No. 138, 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, 2002, the Company's net liability related to its cash flow hedges was $13.1 million. Additionally, at September 30, 2002, the Company had recorded a net of tax cumulative loss to other comprehensive income (equity section of the balance sheet) of $9.8 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the adoption of SFAS No. 133.

6. 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 are shown in the following table. The "Other" column includes items related to non-reportable segments (real estate and pipeline operations) and corporate items.

	Exploration and Production	Gas Distribution	Marketing	Other	Total
			($ in thousands)		
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(1)	4,354	847	--	232	5,433
Provision (benefit) for income taxes(1)	1,902	(1,219)	184	(70)	797
Assets	552,098	147,954	11,309	26,449(2)	737,810(2)
Capital expenditures	25,559	1,450	1	45	27,055
Three months ended September 30, 2001:					
Revenues from external customers	$ 34,079	$ 13,925	$ 11,392	$ --	$ 59,396
Intersegment revenues	1,988	20	25,088	112	27,208
Operating income (loss)	15,913	(2,356)	640	66	14,263
Depreciation, depletion and amortization expense	12,344	1,496	17	24	13,881
Interest expense(1)	4,487	834	--	271	5,592
Provision (benefit) for income taxes(1)	4,382	(1,228)	226	(172)	3,208
Assets	528,140	144,475	9,474	29,473(2)	711,562(2)
Capital expenditures	27,870(3)	1,144	--	139	29,153(3)

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(1)	12,887	2,582	--	670	16,139
Provision (benefit) for income taxes(1)	5,032	729	678	(330)	6,109
Assets	552,098	147,954	11,309	26,449(2)	737,810(2)
Capital expenditures	63,394	4,210	3	222	67,829
Nine months ended September 30, 2001:					
Revenues from external customers	$ 93,570	$ 114,874	$ 64,104	$ --	$ 272,548
Intersegment revenues	23,948	169	98,036	336	122,489
Operating income	56,173	6,274	2,227	203	64,877
Depreciation, depletion and amortization expense	33,429	4,604	50	72	38,155
Interest expense(1)	14,559	2,973	--	800	18,332
Provision (benefit) for income taxes(1)	15,979	1,511	868	(520)	17,838
Assets	528,140	144,475	9,474	29,473(2)	711,562(2)
Capital expenditures	73,503(3)	3,313	17	310	77,143(3)

(1) Interest expense and the provision (benefit) for income taxes by segment reflect an allocation of corporate amounts as debt and the provision (benefit) for income taxes are incurred at the corporate level.
(2) Other assets includes the Company's equity investment in the operations of the NOARK Pipeline System, Limited Partnership, corporate assets not allocated to segments, and assets for non-reportable segments.
(3) Capital expenditures for the Exploration and Production segment include $7.7 million and $16.7 million for the three and nine month periods ended September 30, 2001, related to the consolidated results of a limited partnership. The Company received reimbursement of $6.4 million of the year to date amount from the owner of the minority interest in the partnership.

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, prepaid pension costs and other prepaid expenses. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

7. INTEREST AND INCOME TAXES PAID

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

Nine Months Ended September 30,	2002	2001
	(in thousands)	
Interest payments	$ 12,243	$14,830
Income tax payments	$ --	$ --

8. **MINORITY INTEREST IN PARTNERSHIP**

In the second quarter of 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 the first 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. SEPCO contributed 50% of the capital required to drill the first 14 wells. Revenues and expenses are allocated 65% to SEPCO prior to payout of the investor's initial investment and 85% thereafter.

9. **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, 2002 and December 31, 2001, the principal outstanding for these Notes was $72.0 million and $73.0 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 expire at various dates through July 2003, and are renewable year-to-year thereafter 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 noncapital 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.

10. **NEW ACCOUNTING STANDARDS**

As previously disclosed, in July 2001 the FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). 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. SFAS No. 143 will be effective for the Company beginning January 1, 2003. This standard will require the Company to record asset retirement obligations and asset retirement costs, primarily with respect to its exploration and production properties. The effect of this standard on the Company's results of operations and financial condition is being evaluated.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145, “Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement 13, and Technical Corrections” (SFAS No.145). SFAS No.145 is effective for fiscal years beginning after May 15, 2002. Under the provisions of SFAS No.145 gains and losses from extinguishment of debt generally will no longer be classified as extraordinary items. Beginning January 1, 2003 the Company will be required to reclassify certain prior period amounts related to the extinguishment of debt. This reclassification will not have any impact on the Company’s financial position, results of operations or cash flows.

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 the Company's Form 10-K/A for the year ended December 31, 2001, and analyzes the changes in the results of operations between the three and nine month periods ended September 30, 2002, and the comparable periods of 2001. Certain reclassifications have been made to the prior year's financial statements to conform with the 2002 presentation. These reclassifications had no effect on previously reported net income.

RESULTS OF OPERATIONS

Net income for the three months ended September 30, 2002 was $1.3 million, or $.05 per share, compared to $5.0 million, or $.20 per share, for the same period in 2001. Net income for the nine months ended September 30, 2002 was $9.8 million, or $.37 per share, compared to $27.9 million, or $1.09 per share, for the nine months ended September 30, 2001. The decrease in third quarter earnings resulted primarily from lower natural gas prices and lower equivalent production experienced by the Company's exploration and production segment. The decrease in year-to-date earnings resulted primarily from lower gas prices, partially offset by increased equivalent production.

Exploration and Production

Overview

The Company's 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 its 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 oil and gas prices will not be subject to wide fluctuations in the future.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Revenues (in thousands)	$30,325	$36,067	$90,161	$117,518
Operating income (in thousands)	$9,705	$15,913	$27,098	$56,173
Gas production (MMcf)	8,971	9,420	27,330	26,098
Oil production (MBbls)	165	183	543	535
Total production (MMcfe)	9,961	10,518	30,588	29,308
Average gas price per Mcf	$2.96	$3.37	$2.89	$3.97
Average oil price per Bbl	$22.65	$23.75	$20.87	$24.67

Operating expenses per Mcfe				
Production expenses	$0.48	$0.38	$0.43	$0.43
Production taxes	$0.15	$0.16	$0.17	$0.20
General & administrative expenses	$0.25	$0.21	$0.27	$0.32(1)
Full cost pool amortization	$1.16	$1.15	$1.16	$1.11

(1) Includes $2.0 million, or $.07 per Mcfe for the nine months ended September 30, 2001, for settled litigation.

Revenues and Operating Income

Revenues for the exploration and production segment were down 16% for the three month period and down 23% for the nine month period ended September 30, 2002, both as compared to the same periods in 2001. The decreases were primarily due to lower gas and oil prices received in 2002.

Operating income for the exploration and production segment was down $6.2 million for the three months ended September 30, 2002, and down $29.1 million for the first nine months of 2002, both as compared to the same periods in 2001. The decreases in operating income were primarily due to lower segment revenues.

Production

Gas and oil production during the third quarter of 2002 was 10.0 billion cubic feet (Bcf) equivalent, down from 10.5 Bcfe for the same period in 2001. The comparative decrease in third quarter production primarily resulted from the natural decline in productive capability of the Company's existing properties that has not been fully offset by new discoveries and development drilling. The timing of discoveries and any resulting initial production can impact quarter-to-quarter comparisons. Gas production was 9.0 Bcf for the third quarter of 2002, compared to 9.4 Bcf for the same period in 2001. For the nine months ended September 30, 2002, gas and oil production was 30.6 Bcfe, up 4% from 29.3 Bcfe for the same period in 2001. Gas production was 27.3 Bcf for the first nine months of 2002 up from 26.1 Bcf in 2001. The Company's sales to its gas distribution systems were 3.9 Bcf during the nine months ended September 30, 2002, compared to 3.7 Bcf for the same period in 2001. The Company's oil production was 543 thousand barrels (MBbls) during the first nine months of 2002, compared to 535 MBbls for the same period of 2001.

The Company recently revised its full-year 2002 oil and gas production target to 40-41 Bcfe, down from its previous target of 41-43 Bcfe. This compares to total equivalent production of 39.8 Bcfe in 2001.

The Company is currently in the process of selling its non-strategic Oklahoma properties located outside of the Arkoma Basin. Revenues and production could be lower in the fourth quarter of 2002 as a result of the sale of these properties.

Commodity Prices

The Company realized an average price of $2.96 per thousand cubic feet (Mcf) for its natural gas production for the three months ended September 30, 2002, down 12% from $3.37 per Mcf for the same period of 2001. The Company hedged 20.7 Bcf of gas production in the first nine months of 2002 through fixed-price swaps and zero-cost collars, which had the effect of reducing the average gas price realized by $.03 per Mcf in the third quarter of 2002, and increasing the average gas price realized by $.02 per Mcf during the first nine months of 2002. On a comparative basis, the average realized price during the third quarter of 2001 was increased by $.57 per Mcf and reduced by $.78 per Mcf in the first nine months of 2001, due to the effect of the Company's commodity price hedges.

For the remainder of 2002, the Company has 2.5 Bcf of gas production hedged with collars having an average NYMEX floor price of $3.70 per Mcf and an average NYMEX ceiling price of $4.88 per Mcf. The Company also has 4.2 Bcf of gas production for the remainder of 2002 hedged with fixed price swaps at an average NYMEX price of $3.14 per Mcf. For the years 2003 and 2004 combined, the Company has 34.6 Bcf 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.

The Company received an average price of $20.87 per barrel for its oil production during the nine months ended September 30, 2002, down from $24.67 per barrel for the same period of 2001. The Company's hedging activities lowered the average realized oil price by $2.43 per barrel for the first nine months of 2002, and by $.92 per barrel for the first nine months of 2001. For the remainder of 2002, the Company has a hedge on 83,250 barrels at an average NYMEX price of $20.07 per barrel. For 2003, the Company has a hedge on 240,000 barrels at an average NYMEX price of $25.40 per barrel.

Operating Costs and Expenses

Total operating costs and expenses for the exploration and production segment increased 2% in the third quarter of 2002, as compared to the same period in 2001, primarily due to increased production expenses, largely offset by lower depreciation, depletion and amortization expense. The comparative increase in production expenses resulted from increased compression and salt water disposal costs and a non-recurring accrual of lease operating expenses. The decrease in third quarter depreciation, depletion and amortization expense resulted from lower production volumes. Total operating costs and expenses for the first nine months of 2002 were up 3% compared to the prior year due to increased production expenses and depreciation, depletion and amortization expense, partially offset by lower general and administrative expenses. The comparative decrease in general and administrative expenses in 2002 resulted primarily from costs incurred to settle litigation during 2001. The increase in depreciation, depletion and amortization expense in 2002 was due to the increase in production volumes and an increase in the amortization rate per unit of production. The full cost pool amortization rate for this segment averaged $1.16 per Mcf equivalent for the first nine months of 2002, compared to $1.11 per Mcf equivalent in the first nine months of 2001.

Gas Distribution

Overview

The operating results of the Company's gas distribution segment are highly seasonal. This segment typically realizes operating losses in the second and third quarters of the year and realizes operating income during the winter heating season in the first and fourth quarters. The extent and duration of heating weather also impacts the profitability of this segment, although the Company has a weather normalization clause that lessens 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. For periods subsequent to allowed rate increases, the Company's profitability is impacted by its ability to manage and control this segment's operating costs and expenses. The Company expects to file a rate increase request in the fourth quarter of 2002.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	($ in thousands, except for per Mcf amounts)			
Revenues	$13,063	$13,945	$78,403	$115,043
Gas purchases	$5,490	$6,099	$43,408	$78,536
Operating costs and expenses	$9,816	$10,202	$30,293	$30,233
Operating income (loss)	$(2,243)	$(2,356)	$4,702	$6,274
Deliveries (Bcf)				
Sales and end-use transportation	3.2	3.0	17.2	17.1
Off-system transportation	1.3	1.6	2.0	2.6
Average number of customers	134,807	131,313	136,456	133,890
Average sales rate per Mcf	$8.39	$7.85	$6.57	$9.14
Heating weather - degree days	14	51	2,291	2,378
- percent of normal	--	--	91%	96%

Revenues and Operating Income

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 nine month periods ended September 30, 2002 are down from the comparable period of 2001 primarily due to the significant drop in the cost of the utility's gas supply from the record high levels experienced during 2001. The decrease in the cost of gas supply is reflected in the Company's average rate for its utility sales which decreased during the first nine months of 2002 to $6.57 per Mcf, down from $9.14 per Mcf for the same period in 2001. Costs paid for purchases of natural gas are passed through to the utility's customers under automatic adjustment clauses.

The Company realized a slight improvement in the seasonal operating loss experienced by the gas distribution segment in the third quarter of 2002. Operating income for the first nine months of the year was down 25% compared to the same period in 2001. The decrease was due primarily to a favorable settlement of open issues with the Missouri Public Service Commission in 2001 and general inflationary increases in operating costs and expenses in 2002.

Deliveries
The utility systems delivered 17.2 Bcf to sales and end-use transportation customers during the nine months ended September 30, 2002, compared to 17.1 Bcf for the same period in 2001. Weather for the first nine months of 2002 was 9% warmer than normal and 4% warmer than the same period of the prior year. The weather normalization clause in the Company's rates lessens the impacts of revenue increases and decreases that result from weather variations during the winter heating season.

Operating Costs and Expenses
The changes in purchased gas costs for the 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 of the gas distribution segment for the nine months ended September 30, 2002 were approximately equal with the comparable prior year period.

Marketing and Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Marketing revenues (in thousands)	$33,636	$36,480	$98,272	$162,140
Marketing operating income (in thousands)	$458	$640	$1,742	$2,227
Gas volumes marketed (Bcf)	11.6	13.5	36.2	36.9

Marketing
The decrease in gas marketing revenues for the nine months ended September 30, 2002, relates to a substantial decrease in natural gas commodity prices from the prior year, and was largely offset by a comparable decrease in purchased gas costs. Operating income for the marketing segment was $1.7 million for the first nine months of 2002, compared to $2.2 million for the same period in 2001. The Company marketed 36.2 Bcf of gas in the first nine months of 2002, compared to 36.9 Bcf for the same period in 2001. Volumes marketed for Southwestern's exploration and production subsidiaries were 24.0 Bcf for the first nine months of 2002, compared to 23.5 Bcf in 2001.

NOARK Pipeline

The Company's share of the NOARK Pipeline System Limited Partnership (NOARK) pre-tax loss included in other income was $.4 million for the first nine months of 2002, down from $1.0 million for the same period in 2001.

Interest Expense

Interest expense decreased 3% for the third quarter of 2002 and 12% for the first nine months of 2002, both as compared to the same periods in 2001, due to lower average borrowings and a lower average interest rate, partially offset by a lower level of capitalized interest. Interest is capitalized in the exploration and production segment on costs that are unevaluated and excluded from amortization.

Income Taxes

The changes in the provisions for deferred income taxes recorded in the three and nine month periods ended September 30, 2002, as compared to the same periods in 2001, resulted primarily from the decrease in the level of taxable income in 2002. 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.

Pension Expense

As disclosed in the Company's Form 10K/A, substantially all of the Company's employees are covered by defined benefit and postretirement benefit plans. The Company's return on the assets of these plans to date in 2002 has been negative which, combined with other factors, is expected to result in an increase in pension expense and the Company's required funding of the plans for 2003. Such pension expense and funding for 2003 will be finalized based on actuarial assumptions and calculations to be completed in early 2003.

Comprehensive Income

In the second quarter of 2002, the Company corrected its presentation of comprehensive income for prior periods to properly reflect amounts associated with hedging activities. This correction resulted in a decrease in comprehensive income of $15.3 million for the nine months ended September 30, 2001. This correction had no effect on the Company's previously reported net income, earnings per share or cash flows, nor did it have any impact on the Company's balance sheet. The prior period corrections in the presentation of comprehensive income were reflected in amendments to the Company's filings on Form 10-K for the year ended December 31, 2001 and Form 10-Q for the three months ended March 31, 2002, both of which were filed in September 2002 in conjunction with the Company's change in auditors from Arthur Andersen LLP to PricewaterhouseCoopers LLP.

CHANGES IN FINANCIAL CONDITION

Changes in the Company's financial condition at September 30, 2002, as compared to December 31, 2001, primarily reflect changes in the Company's cash flow from operating activities, the seasonal nature of the Company's gas distribution segment, the timing of cash payments and receipts and the effects of accounting for the Company's hedging activities as required by SFAS No. 133.

The Company's cash flow from operating activities is highly dependent upon market prices that the Company receives for its gas and oil production. The price that the Company receives for its production is also heavily influenced by the Company's commodity hedging activities. Natural gas and oil prices are subject to wide fluctuations and the prices realized for the nine month period ended September 30, 2002 have declined significantly compared to prices realized during the same period of 2001.

Routine capital expenditures have predominantly been funded through cash provided by operations. For the first nine months of 2002 and 2001, cash provided by operating activities was $68.4 million and $114.7 million, respectively, and met or exceeded the total of these routine requirements.

Financing Requirements

In July 2001, the Company arranged an unsecured revolving credit facility with a group of banks. The revolving credit facility has a current capacity of $140 million and expires in July 2004. The interest rate on the current facility is 150 basis points over the current London Interbank Offered Rate (LIBOR), and was 4.6%, including the effects of interest rate swaps, at September 30, 2002. The interest rate increased 12.5 basis points in July 2002 as the result of a downgrade of the Company's public debt by Moody's from Baa3 to Ba2. Standard and Poor's continues to rate the Company's public debt at BBB.

The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 70% of its total capital, must maintain a certain level of shareholders' equity, and the Company must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of at least 3.75 or higher through December 31, 2002. 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. At September 30, 2002, the Company's revolving credit facility had a balance of $128.2 million and was classified as long-term debt in the Company's balance sheet. The Company has also entered into interest rate swaps for calendar year 2002 that allow the Company to pay an average fixed interest rate of 4.9% (based upon current rates under the revolving credit facility) on $100.0 million of its outstanding revolving debt. Interest rate swaps entered into for 2003 will allow the Company to pay a fixed rate of 3.8% (based upon current rates under the revolving credit facility) on $40.0 million of its outstanding revolving debt.

During the first nine months of 2002, the Company's total debt increased by $3.2 million. Total debt at September 30, 2002, accounted for 66.2% of the Company's capitalization (excluding the Company's several guarantee of NOARK's obligations). The percentage of debt to capitalization at September 30, 2002, would be 65.0% without consideration of the $9.8 million of accumulated other comprehensive loss recorded in the equity section of the Company's balance sheet. The other comprehensive loss in the September 30, 2002 balance sheet resulted from the Company's hedging activities and was recorded in accordance with the requirements of SFAS No. 133.

The Company's capital expenditures for the first nine months of 2002 were $67.8 million, compared to $77.1 million for the same period in 2001. Planned capital investments during calendar year 2002 are currently expected to be approximately $88.0 million. This amount includes a recently announced $10.0 million increase in the Company's capital investments for its infill drilling program at its Overton Field in East Texas.

The Company is in the process of selling its non-strategic Oklahoma properties located outside of the Arkoma Basin. Proceeds from this sale will be used to pay down debt and help fund the increase in planned capital investments.

At September 30, 2002, the NOARK partnership had outstanding debt totaling $72.0 million. The Company and the other general partner of NOARK have severally guaranteed the principal and interest payments on the NOARK debt. The Company's share of the several guarantee is 60%.

Working Capital

Accounts receivable has declined since December 31, 2001, primarily due to the seasonality of the gas distribution segment's operations. Changes in accounts payable and other current assets and liabilities since December 31, 2001 are due primarily to the timing of expenditures and receipts and the recording of amounts related to the Company's hedging activities in accordance with SFAS No. 133. Over-recovered purchased gas costs for the Company's gas distribution segment were $5.1 million at September 30, 2002, compared to $8.2 million at December 31, 2001. Purchased gas costs are recovered from the Company's utility customers in subsequent months through automatic cost of gas adjustment clauses included in the utility's filed rate tariffs. At September 30, 2002, the Company had a current hedging asset of $3.3 million, a current hedging liability of $13.9 million, and a regulatory liability of $3.0 million recorded as a result of the provisions of SFAS No. 133.

CRITICAL ACCOUNTING POLICIES

Oil and Gas Properties

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas properties. The Company reviews the carrying value of its oil and gas properties under the full cost accounting rules of the Securities and Exchange Commission 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 oil and natural gas properties exceed the ceiling, the Company 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 oil and gas prices may subsequently increase the ceiling.

The risk that the Company will be required to write-down the carrying value of its oil and natural gas properties increases when oil and natural gas prices are depressed or if there are substantial downward revisions in estimated proved reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the probability of a ceiling test write-down. Based on oil and natural gas prices in effect on September 30, 2002, the unamortized cost of the Company's oil and natural gas properties did not exceed the ceiling of proved oil and natural gas reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly reporting periods.

Oil and natural gas reserves used in the full cost method of accounting cannot be measured exactly. The Company's estimate of oil and natural gas 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. The Company engages the services of an independent petroleum consulting firm to review reserves as prepared by the Company's reservoir engineers.

Hedging

The Company uses 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. The Company's policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. The primary market risks related to the Company's 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.

The Company's derivative instruments are accounted for under SFAS No. 133 and are recorded at fair value in its financial statements. The Company utilizes market-based quotes from its hedge counterparties to value these open positions. These valuations are recognized as assets or liabilities in the Company's balance sheet and, to the extent an open position is an effective cash flow hedge on equity production or interest rates, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected in oil and gas sales or in gas purchases. Results of settled interest rate hedges are reflected in interest expense. Any ineffective hedge, derivative not qualifying for accounting treatment as a hedge, or any ineffective portion of a hedge is recognized immediately in earnings. Future market price volatility could create significant changes to the hedge positions recorded in the Company's financial statements. See Part I, Item 3 - Quantitative and Qualitative Disclosures about Market Risk for additional information regarding the Company's hedging activities.

Regulated Utility Operations

The Company's utility operations are subject to the rate regulation and accounting requirements of the Arkansas Public Service Commission. Allocations of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from bases 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 and there is none currently anticipated. However, should this occur, certain of these assets may no longer meet the criteria for deferred recognition and, accordingly, a write-off of regulatory assets and stranded costs may be required.

See further discussion of the Company's significant accounting policies in Note 1 of Notes to Consolidated Financial Statements in the Company’s 2001 annual report on Form 10-K/A.

FORWARD LOOKING INFORMATION

All statements, other than historical 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. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for gas and oil, the timing and extent of the Company’s success in discovering, developing, producing, and estimating reserves, property acquisition or divestiture activities that may occur, the effects of weather and regulation on the Company’s gas distribution segment, increased competition, legal and economic factors, governmental regulation, the financial impact of accounting regulations, changing market conditions, the comparative cost of alternative fuels, conditions in capital markets and changes in interest rates, availability of oil field services, drilling rigs and other equipment, as well as various other factors beyond the Company’s control.

PART I

Item 3 - Quantitative and Qualitative Disclosures About Market Risk

Market risks relating to the Company's operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. The Company uses 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. 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

The Company's 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 5% of accounts receivable. See the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

The Company's revolving debt obligations are sensitive to changes in interest rates. The Company's 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. The Company has entered into interest rate swaps for calendar year 2002 that allow the Company to pay an average fixed interest rate of 4.9% (based upon current rates under the revolving credit facility) on $100.0 million of its outstanding revolving debt. The Company's revolving debt was $125.0 million at December 31, 2001, and had an average interest rate of 3.4%. At September 30, 2002, the Company's revolving debt was $128.2 million with an average interest rate of 4.6%, including the effect of the interest rate swaps. Other than the Company's revolving debt, there have been no material changes in the interest rate risk information that was presented in the Company's 2001 annual report on Form 10-K/A.

The Company's interest rate swaps have a carrying amount of $1.9 million, calculated as the contractual payments for interest on the notional amount to be exchanged under futures contracts and does not represent amounts recorded in the Company's financial statements. The fair value of $1.1 million represents the value for the same contracts using comparable market prices at September 30, 2002. At September 30, 2002, the "Carrying Amount" exceeded the "Fair Value" of interest rate swaps by $.8 million.

Commodities Risk

The Company uses over-the-counter natural gas and crude oil swap agreements and options to hedge sales of Company production, to hedge activity in its marketing segment, and to hedge the purchase of gas in its 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 the Company pays to (production hedge) or receives 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 the Company's 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 the Company's 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 the Company has to each counterparty are periodically reviewed to ensure limited credit risk exposure.

The following table provides information about the Company's 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 the Company's financial statements. The "Fair Value" represents values for the same contracts using comparable market prices at September 30, 2002. At September 30, 2002, the "Carrying Amount" exceeded the "Fair Value" of these financial instruments by $12.3 million.

	Expected Maturity Date					
	2002		2003		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Production and Marketing						
Natural Gas:						
Swaps with a fixed price receipt						
Contract volume (Bcf)	4.2		13.3		3.2	
Weighted average price per Mcf	$3.14		$3.47		$3.99	
Contract amount (in millions)	$13.0	$9.3	$46.1	$38.2	$12.8	$13.1
Price collars						
Contract volume (Bcf)	3.4		15.9		4.0	
Weighted average floor price per Mcf	$3.67		$3.16		$3.25	
Contract amount of floor (in millions)	$12.6	$13.0	$50.1	$52.2	$13.0	$14.2
Weighted average ceiling price per Mcf	$4.84		$4.84		$4.75	
Contract amount of ceiling (in millions)	$16.6	$16.4	$76.7	$71.7	$19.0	$17.4
Oil:						
Swaps with a fixed price receipt						
Contract volume (MBbls)	83		240		-	
Weighted average price per Bbl	$20.07		$25.40		-	
Contract amount (in millions)	$1.7	$0.9	$6.1	$6.0	-	-
Natural Gas Purchases						
Swaps with a fixed price payment						
Contract volume (Bcf)	1.4		2.7		-	
Weighted average price per Mcf	$3.42		$3.42		-	
Contract amount (in millions)	$4.8	$5.8	$9.2	$11.2	-	-

PART II

OTHER INFORMATION

Items 1 – 3

No developments required to be reported under Items 1 – 3 occurred during the quarter ended September 30, 2002.

Item 4 - Controls and Procedures

a. Within the 90 days prior to the filing date of this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Based upon that evaluation, the Company's Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective. Disclosure controls and procedures are controls and procedures that are designed to ensure that information required to be disclosed in Company reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

b. There have been no significant changes in our internal controls or in other factors that could significantly affect internal controls subsequent to the date we carried out this evaluation.

Items 5 – 6(a)

No developments required to be reported under Items 5 – 6(a) occurred during the quarter ended September 30, 2002.

Item 6(b)

On August 14, 2002, the Company filed a current report on Form 8-K containing management certifications required under Section 906 of the Sarbanes-Oxley Act of 2002. The certifications accompanied the registrant's filing on Form 10-Q for the quarter ended June 30, 2002.

On September 24, 2002, the Company filed a current report on Form 8-K containing management certifications required under Section 906 of the Sarbanes-Oxley Act of 2002. The certifications accompanied the registrant's filing on Form 10-Q/A for the quarter ended March 31, 2002.

On September 24, 2002, the Company filed a current report on Form 8-K containing management certifications required under Section 906 of the Sarbanes-Oxley Act of 2002. The certifications accompanied the registrant's filing on Form 10-K/A for the year ended December 31, 2001.

On September 27, 2002, the Company filed a current report on Form 8-K containing the Company's slide presentation made to investors on September 27, 2002 at the John S. Herold Pacesetters Energy Conference in Old Greenwich, Connecticut.

On October 18, 2002, the Company filed a current report on Form 8-K containing the Company's press release dated October 17, 2002, announcing the approval of an additional $10 million to the Company's previous 2002 capital budget and providing updated production guidance for 2002.

All other filings on Form 8-K during the quarter ended September 30, 2002 have been previously disclosed in the Company's Form 10-Q for the second quarter of 2002.

Signatures

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

SOUTHWESTERN ENERGY COMPANY
Registrant

DATE: October 25, 2002

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

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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-14 and 15d-14) for the registrant and we have:

   (a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   (c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: October 25, 2002

/s/ Harold M. Korell
Harold M. Korell

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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-14 and 15d-14) for the registrant and we have:

    (a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

    (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

    (c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, 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 in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

    (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: October 25, 2002

/s/ Greg. D. Kerley
Greg D. Kerley