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, 2005**

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ________ to _________

Commission file number **1-08246**

Southwestern Energy Company

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 by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes: ___ No: X

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 26, 2005
Common Stock, Par Value $0.10	83,365,176

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,	
	2005	2004	2005	2004
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 118,466	$ 82,637	$ 337,929	$ 257,494
Gas marketing	32,822	17,989	87,572	42,849
Oil sales	9,415	5,118	22,954	13,460
Gas transportation and other	1,424	5,651	7,188	13,809
	162,127	111,395	455,643	327,612
Operating Costs and Expenses:				
Gas purchases - utility	5,971	4,523	44,872	39,573
Gas purchases - marketing	30,770	16,964	82,900	39,599
Operating expenses	13,980	11,070	38,326	31,280
General and administrative expenses	11,437	9,151	32,048	25,425
Depreciation, depletion and amortization	25,527	19,960	68,783	52,577
Taxes, other than income taxes	7,241	4,290	18,106	12,168
	94,926	65,958	285,035	200,622
Operating Income	67,201	45,437	170,608	126,990
Interest Expense:				
Interest on long-term debt	6,047	4,626	16,211	13,423
Other interest charges	293	300	961	1,128
Interest capitalized	(1,629)	(714)	(3,268)	(2,007)
	4,711	4,212	13,904	12,544
Other Income (Expense)	427	(543)	626	(1,090)
Income Before Income Taxes and Minority Interest	62,917	40,682	157,330	113,356
Minority Interest in Partnership	(477)	(366)	(885)	(1,196)
Income Before Income Taxes	62,440	40,316	156,445	112,160
Provision for Income Taxes - Deferred	22,971	14,917	57,541	41,499
Net Income	$ 39,469	$ 25,399	$ 98,904	$ 70,661
Earnings Per Share:(1)				
Basic	$ 0.53	$ 0.36	$ 1.36	$ 0.99
Diluted	$ 0.51	$ 0.34	$ 1.31	$ 0.96
Weighted Average Common Shares Outstanding:(1)				
Basic	74,096,324	71,545,282	72,947,768	71,329,822
Diluted	76,832,300	74,180,222	75,655,620	73,687,436

(1) 2004 restated to reflect a two-for-one stock split effected in June 2005.

The accompanying notes are an integral part of the financial statements

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

ASSETS

	September 30, 2005	December 31, 2004
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 388,201	$ 1,235
Accounts receivable	88,865	86,268
Inventories, at average cost	44,801	32,248
Deferred income tax assets	63,900	3,600
Other	31,888	7,634
Total current assets	617,655	130,985
Investments	15,820	15,465
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method	1,774,747	1,483,452
Gas distribution systems	214,034	207,447
Gathering systems	7,893	372
Construction-in-progress - drilling rigs	31,547	-
Gas in underground storage	32,254	32,254
Other	40,262	37,820
	2,100,737	1,761,345
Less: Accumulated depreciation, depletion and amortization	845,145	777,189
	1,255,592	984,156
Other Assets	19,318	15,538
Total Assets	$ 1,908,385	$ 1,146,144

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	September 30, 2005	December 31, 2004
	(in thousands)	
Current Liabilities		
Notes payable	$ 125,000	$ -
Accounts payable	115,220	81,586
Taxes payable	8,716	9,333
Hedging liability - FAS No. 133	198,777	29,886
Over-recovered purchased gas costs	8,316	1,412
Other	18,188	11,483
Total current liabilities	474,217	133,700
Long-Term Debt	100,000	325,000
Other Liabilities		
Deferred income taxes	224,644	203,996
Long-term hedging liability	90,642	5,798
Other	18,624	18,114
	333,910	227,908
Commitments and Contingencies		
Minority Interest in Partnership	12,243	11,859
Shareholders' Equity		
Common stock, $.10 par value; authorized 220,000,000 shares, issued 84,226,168 shares in 2005 and 74,451,168 shares in 2004 (1)	8,423	7,445
Additional paid-in capital (1)	711,698	125,031
Retained earnings	449,365	350,461
Accumulated other comprehensive income (loss)	(172,147)	(19,816)
Common stock in treasury, at cost, 861,892 shares at September 30, 2005 and 1,643,152 shares at December 31, 2004 (1)	(4,801)	(9,156)
Unamortized cost of restricted shares issued under stock incentive plan, 614,457 shares at September 30, 2005 and 640,576 shares at December 31, 2004 (1)	(4,523)	(6,288)
	988,015	447,677
Total Liabilities and Shareholders' Equity	$ 1,908,385	$ 1,146,144

(1) 2004 restated to reflect a two-for-one stock split effected in June 2005.

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,	
	2005	2004
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 98,904	$ 70,661
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	71,799	55,343
Deferred income taxes	57,541	41,499
Unrealized (gain) loss on derivatives	(9,271)	2,303
Gain on sale of other property, plant & equipment	-	(5,802)
Equity in (income) loss of NOARK partnership	(354)	1,100
Minority interest in partnership	384	241
Change in operating assets and liabilities:		
Accounts receivable	(2,597)	11,585
Inventories	(12,236)	(5,034)
Under/over-recovered purchased gas costs	6,904	(2,774)
Accounts payable	3,906	11,742
Taxes payable	(617)	(547)
Other operating assets and liabilities	1,459	3,002
Net cash provided by operating activities	215,822	183,319
Cash Flows From Investing Activities		
Capital expenditures	(317,375)	(211,371)
Proceeds from sale of property, plant and equipment	1,040	7,121
Other items	(448)	11
Net cash used in investing activities	(316,783)	(204,239)
Cash Flows From Financing Activities		
Net proceeds from equity offering	579,956	-
Payments on revolving long-term debt	(563,800)	(312,600)
Borrowings under revolving long-term debt	463,800	329,300
Debt issuance costs	(1,180)	(1,514)
Change in bank drafts outstanding	4,974	1,504
Proceeds from exercise of common stock options	4,177	4,187
Net cash provided by financing activities	487,927	20,877
Increase (decrease) in cash and cash equivalents	386,966	(43)
Cash and cash equivalents at beginning of year	1,235	1,277
Cash and cash equivalents at end of period	$ 388,201	$ 1,234

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 Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Unamortized Restricted Stock Awards	Total
	Shares	Amount						
					(in thousands)			
Balance at December 31, 2004	37,226	$ 3,723	$ 128,753	$ 350,461	$ (19,816)	$ (9,156)	$ (6,288)	$ 447,677
Comprehensive income:								
Net income	-	-	-	98,904	-	-	-	98,904
Change in value of derivatives	-	-	-	-	(152,331)	-	-	(152,331)
Total comprehensive income (loss)	-	-	-	-	-	-	-	(53,427)
Two-for-one stock split	37,225	3,722	(3,722)	-	-	-	-	-
Issuance of common stock	9,775	978	578,978	-	-	-	-	579,956
Exercise of stock options	-	-	7,478	-	-	4,415	-	11,893
Issuance of restricted stock	-	-	310	-	-	62	(372)	-
Cancellation of restricted stock	-	-	(99)	-	-	(122)	221	-
Amortization of restricted stock	-	-	-	-	-	-	1,916	1,916
Balance at September 30, 2005	84,226	$ 8,423	$ 711,698	$ 449,365	$ (172,147)	$ (4,801)	$ (4,523)	$ 988,015

RECONCILIATION OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	For the three months ended September 30,		For the nine months ended September 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Balance, beginning of period	$ (50,334)	$ (24,201)	$ (19,816)	$ (12,520)
Current period reclassification to earnings	24,401	5,259	33,328	12,900
Current period change in derivative instruments	(146,214)	(15,491)	(185,659)	(34,813)
Balance, end of period	$ (172,147)	$ (34,433)	$ (172,147)	$ (34,433)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
September 30, 2005

(1) BASIS OF PRESENTATION

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

In June 2005, the Company distributed additional shares of its common stock in a two-for-one stock split that was declared by its board of directors in May 2005. All historical per share information in the financial statements and footnotes has been adjusted to reflect the two-for-one stock split.

(2) ISSUANCE OF COMMON STOCK

In the third quarter of 2005, the Company consummated an underwritten offering of 9,775,000 shares of its common stock pursuant to an effective registration statement filed with the Securities and Exchange Commission. The net proceeds of the offering were approximately $580.0 million after deduction of the underwriting discounts and offering expenses payable by the Company. Approximately $60.7 million of the net proceeds will be used to fund the recent increase in the Company's 2005 capital program that was contingent upon the consummation of the offering and $125 million will be used to repay the Company's 6.70% senior notes upon maturity in December 2005. The remaining net proceeds will be used for general corporate purposes, including the funding of the Company's remaining 2005 and future capital expenditures relating to the acceleration of the Company's Fayetteville Shale resource play. Pending such uses, approximately $193 million was used to pay down outstanding indebtedness under the Company's revolving credit facility and the remainder has been invested in short-term marketable securities.

(3) GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to its natural gas and oil properties. Under this method, all such costs (productive and nonproductive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of this ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. At September 30, 2005, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At September 30, 2005, our standardized measure was calculated based upon the latest quoted market prices of $15.22 per Mcf for Henry Hub gas and $66.24 per barrel for West Texas Intermediate oil, adjusted for market differentials. The price for Henry Hub gas is based upon reported prices for September 26, 2005, which was the last reported date for Henry Hub gas due to Hurricane Rita. A significant decline in natural gas and oil prices from the above-referenced 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.

(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 number of shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock. All of the Company's outstanding options at September 30, 2005 (3,664,402 options with an average exercise price of $6.60) were included in the calculation of diluted shares for both the three and nine month periods of 2005. At September 30, 2004, options for 8,000 shares, with an average exercise price of $19.87 were not included in the calculation of diluted shares because they would have had an antidilutive effect. Options for 4,425,534 shares at September 30, 2004, with a weighted average exercise price of $5.30 were included in the calculation of diluted shares. The number of weighted average restricted shares included in the calculation of diluted shares was 444,311 and 417,206 for the nine months ended September 30, 2005 and 2004, respectively. The number of options and the option prices, and the number of restricted shares for both 2004 and 2005 reflect the two-for-one stock split distributed in the second quarter of 2005.

(5) DEBT

Debt balances as of September 30, 2005 and December 31, 2004 consisted of the following:

	September 30, 2005	December 31, 2004
	(in thousands)	
Short-term:		
6.70% Senior notes due December 2005	$ 125,000	$ -
Long-term:		
Senior notes:		
6.70% Series due December 2005	$ -	$ 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
	100,000	225,000
Other:		
Variable rate (3.66% at December 31, 2004) unsecured revolving credit arrangements	-	100,000
Total long-term debt	$ 100,000	$ 325,000
Total debt	$ 225,000	$ 325,000

In January 2005, the Company arranged a new $500 million five-year unsecured revolving credit facility that amended and restated its existing $300 million three-year credit facility that would have expired in January 2007 and replaced a smaller unsecured credit facility that would have matured at the same time. The interest rate on the new credit facility is calculated based upon the Company's debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company's subsidiaries to incur debt. At September 30, 2005, the Company's capital structure consisted of 19% debt (excluding its several guarantee of NOARK's obligations and including the current notes payable) and 81% equity, with a ratio of EBITDA to interest expense of 17.4, and the Company was in compliance with its debt agreements.

As indicated in the table above, the 6.70% senior notes mature in December 2005. The Company intends to use a portion of the net proceeds from its recent common stock offering to repay these notes and, accordingly, these notes are classified as short-term.

(6) DERIVATIVES AND RISK MANAGEMENT

The Company applies Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149 which 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, 2005, the Company's net liability related to its commodity hedges was $264.2 million. Additionally, at September 30, 2005, the Company had recorded a net of tax cumulative loss to other comprehensive income (the equity section of the balance sheet) of $171.1 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Assuming the market prices of futures as of September 30, 2005 remain unchanged, the Company would expect to transfer an aggregate loss of approximately $183.9 million from accumulated other comprehensive income to pre-tax earnings during the next 12 months. The changes in accumulated other comprehensive income (loss) related to derivatives were a loss of $193.4 million ($121.8 million after tax) and a loss of $16.2 million ($10.2 million after tax) for the three months ended September 30, 2005 and 2004, respectively, and losses of $241.8 million ($152.3 million after tax) and $34.8 million ($21.9 million after tax) for the nine months ended September 30, 2005 and 2004, respectively. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the application of FAS 133.

In the third quarter of 2005, a loss associated with the ineffectiveness of our cash flow hedges was more than offset by a gain on our basis hedges that do not qualify as cash flow hedges resulting in a net gain of $8.7 million and increasing our average gas price realized in the third quarter of 2005 by $0.58 per Mcf.

(7) SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards No. 131 "Disclosures about Segments of an Enterprise and Related Information." The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the Exploration and Production segment are derived from the production and sale of natural gas and crude oil. Revenues for the Gas Distribution segment arise from the transportation and sale of natural gas at retail. The Gas Gathering and Marketing segment, referred to as Midstream Services, generates revenue through the marketing of both Company and third-party produced gas volumes and gathering fees associated with the transportation of natural gas to market. Gathering revenues have been insignificant to-date but could increase in the future depending upon the level of production from our Fayetteville Shale area. In prior periods of 2005, capital expenditures and assets relating to gas gathering were included in the Exploration and Production segment. The 2005 capital expenditures and September 30, 2005 assets for the Exploration and Production segment have been adjusted to exclude the gas gathering amounts and the gas gathering expenditures and assets are now included in the Midstream Services segment.

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

	Exploration And Production	Gas Distribution	Midstream Services	Other	Total
			(in thousands)		
Three months ended September 30, 2005:					
Revenues from external customers	$ 108,679	$ 20,243	$ 33,205	$ --	$ 162,127
Intersegment revenues	5,590	23	100,407	112	106,132
Operating income (loss)	68,861	(3,201)	1,520	21	67,201
Depreciation, depletion and amortization expense	23,813	1,681	10	23	25,527
Interest expense [1]	3,245	965	240	261	4,711
Provision (benefit) for income taxes [1]	23,974	(1,566)	466	97	22,971
Assets	1,240,216	168,134	64,622	435,413 [2]	1,908,385
Capital expenditures	145,961 [3]	3,042	3,753	1,469	154,225
Three months ended September 30, 2004:					
Revenues from external customers	$ 70,993	$ 18,146	$ 17,989	$ 4,267	$ 111,395
Intersegment revenues	4,677	24	67,061	112	71,874
Operating income (loss)	43,113	(2,690)	712	4,302	45,437
Depreciation, depletion and amortization expense	18,304	1,624	9	23	19,960
Interest expense [1]	2,834	1,063	106	209	4,212
Provision (benefit) for income taxes [1]	14,766	(1,387)	224	1,314	14,917
Assets	838,802	162,391	21,126	40,307 [2]	1,062,626
Capital expenditures	87,721 [3]	2,026	-	1,143	90,890

Nine months ended September 30, 2005:					
Revenues from external customers	$ 260,386	$ 107,301	$ 87,956	$ --	$ 455,643
Intersegment revenues	23,466	149	217,023	336	240,974
Operating income	165,191	1,885	3,488	44	170,608
Depreciation, depletion and amortization expense	63,613	5,068	31	71	68,783
Interest expense (1)	9,686	2,995	437	786	13,904
Provision (benefit) for income taxes (1)	56,878	(477)	1,122	18	57,541
Assets	1,240,216	168,134	64,622	435,413 (2)	1,908,385
Capital expenditures(3)	323,337 (3)(4)	7,825	7,901 (4)	1,845	340,908
Nine months ended September 30, 2004:					
Revenues from external customers	$ 176,627	$ 102,335	$ 42,849	$ 5,801	$ 327,612
Intersegment revenues	23,986	106	175,896	336	200,324
Operating income	113,994	4,692	2,410	5,894	126,990
Depreciation, depletion and amortization expense	47,640	4,840	27	70	52,577
Interest expense (1)	8,273	3,338	246	687	12,544
Provision for income taxes (1)	38,679	497	801	1,522	41,499
Assets	838,802	162,391	21,126	40,307 (2)	1,062,626
Capital expenditures(3)	210,732	5,207	1	1,789	217,729

(1) Interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as debt and income tax expense are incurred at the corporate level.
(2) Other assets include the Company's investment in marketable securities, the Company's equity investment in the operations of the NOARK Pipeline System, Limited Partnership, corporate assets not allocated to segments, and assets for non-reportable segments.
(3) Exploration and Production capital expenditures include $14.2 million and $24.8 million for the three and nine month periods ended September 30, 2005, respectively, and $3.8 million and $6.4 million for the three and nine month periods ended September 30, 2004, respectively, relating to the change in accrued expenditures between periods.
(4) $4.1 million of capital expenditures relating to gas gathering activities previously included in the Exploration and Production segment are now included in the Midstream Services segment.

Included in intersegment revenues of Midstream Services are $90.5 million and $67.1 million for the third quarters of 2005 and 2004, respectively, and $199.2 million and $175.9 million for the nine months ended September 30, 2005 and 2004, respectively, for marketing of the Company's exploration and production sales. Intersegment sales by the Exploration and Production segment and Midstream Services 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:

	For the nine months ended September 30,	
	2005	2004
	(in thousands)	
Interest payments	$ 12,392	$ 9,339
Income tax payments	$ 5	$ --

(9) CONTINGENCIES AND COMMITMENTS

The Company and the other general partner of NOARK, Enogex, Inc. ("Enogex"), have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. At September 30, 2005 and December 31, 2004, the outstanding principal for these notes was $66.0 million and $67.0 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 to the extent not funded by operations of the pipeline. Additionally, the Company's gas distribution subsidiary has a transportation contract for firm capacity of 66.9 MMcfd on NOARK's integrated pipeline system under which approximately $4.0 million in costs have been incurred by our gas distribution subsidiary in 2005. This contract expires in 2014.

In September 2005, Enogex announced that it had entered into an agreement to sell the subsidiary that holds its 75% interest in NOARK to Atlas Pipeline Partners, L.P., subject to regulatory review and customary closing conditions. Enogex stated that a portion of the sale proceeds will be used to redeem their 40% share of the 7.15% Notes due 2018.

The Company leases certain office space and equipment under non-cancelable operating leases expiring through 2013. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At September 30, 2005, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $0.5 million in 2005, $1.8 million in 2006, $1.8 million in 2007, $1.7 million in 2008, $1.6 million in 2009 and $2.5 million thereafter. Total rent expense for all operating leases was $1.2 million for the first nine months of 2005 and $1.0 million for the comparable period of 2004.

The Company's utility segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties. These costs are recoverable from the utility's end-use customers. At September 30, 2005, future payments under these non-cancelable demand contracts are $2.7 million in 2005, $10.0 million in 2006, $8.8 million in 2007, $9.2 in 2008, $9.6 million in 2009 and $51.6 million thereafter. Additionally, the E&P segment has a commitment to a third party for demand transportation charges. At September 30, 2005, future payments under these non-cancelable demand contracts are $1.1 million in 2005, $3.0 million in 2006, $0.7 million in 2007, $0.6 million in 2008, $0.6 million in 2009 and $0.4 million thereafter.

On July 1, 2005, the Company entered into an agreement to fabricate five new land drilling rigs for an aggregate purchase price of $37.7 million. Including ancillary equipment and supplies, the total cost of these rigs is approximately $48.5 million. Scheduled payments under this agreement are $27.7 million in 2005 and $10.0 million in 2006. On September 29, 2005, the Company entered into an agreement to fabricate an additional five land drilling rigs for an aggregate purchase price of $40.7 million. Including ancillary equipment and supplies, the total cost of the additional five rigs is approximately $49.2 million. Scheduled payments under this agreement are $10.2 million in 2005 and $30.5 million in 2006, assuming that commencement of the fabrication of the first of the five rigs does not occur in 2005.

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

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

A lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure prospect in Louisiana. The allegations were contested and, in 2002, the Company was granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying the Company’s motion for summary judgment and granting the motion for summary judgment of the other party. The Company’s motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. The Company is pursuing this decision to the Texas Supreme Court. Should the other party prevail on the appeal, the Company could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by the Company and its legal counsel, no accrual for loss is currently recorded.

(10) ACCOUNTING FOR STOCK-BASED COMPENSATION

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2005	2004	2005	2004
Net income, as reported	$ 39,469	$ 25,399	$ 98,904	$ 70,661
Add back: Amortization of restricted stock, net of related tax effects	403	302	1,207	912
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(816)	(563)	(2,440)	(1,755)
Pro forma net income	$ 39,057	$ 25,138	$ 97,672	$ 69,818
Earnings per share:				
Basic - as reported	$ 0.53	$ 0.36	$ 1.36	$ 0.99
Basic - pro forma	0.53	0.35	1.34	0.98
Diluted - as reported	0.51	0.34	1.31	0.96
Diluted - pro forma	0.51	0.34	1.29	0.95

There were no options granted in the first nine months of 2005. There were 11,000 options (pre-split basis) granted in the first nine months of 2004 with a fair value of $0.1 million. The fair value of each option grant in 2004 was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: no dividend yield; expected volatility of 48.7%; risk-free interest rate of 3.7%; and expected lives of 6 years.

As discussed further in Note 13 below, "New Pronouncements," the Company will adopt the provisions of FAS 123 (Revised 2004) in the first quarter of 2006. This standard will require the recognition of the fair value cost of equity awards, including stock options, as an expense over the service period provided by employees and directors.

(11) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. Net periodic pension and other postretirement benefit costs include the following components for the three- and nine- month periods ended September 30, 2005 and 2004:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2005	2004	2005	2004
	(in thousands)			
Service cost	$ 631	$ 601	$ 1,893	$ 1,803
Interest cost	941	923	2,823	2,769
Expected return on plan assets	(1,194)	(1,136)	(3,582)	(3,408)
Amortization of prior service cost	110	111	330	333
Amortization of net loss	81	58	243	175
Net periodic benefit cost	$ 569	$ 557	$ 1,707	$ 1,672

	Postretirement Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2005	2004	2005	2004
	(in thousands)			
Service cost	$ 43	$ 44	$ 129	$ 131
Interest cost	50	63	150	189
Expected return on plan assets	(14)	(10)	(42)	(31)
Amortization of net loss	10	25	30	76
Amortization of transition obligation	22	22	66	65
Net periodic benefit cost	$ 111	$ 144	$ 333	$ 430

The Company currently expects to contribute $1.8 million to its pension plans and $0.4 million to its postretirement benefit plans in 2005. As of September 30, 2005, the $1.8 million has been contributed to the pension plans, and $0.3 million of the $0.4 million has been contributed to the Company’s postretirement benefit plans.

(12) ASSET RETIREMENT OBLIGATIONS

Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," (FAS 143) was adopted by the Company on January 1, 2003. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company owns natural gas and oil properties which require expenditures to plug and abandon the wells when reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period the liability is incurred (at the time the wells are drilled or acquired). The following table summarizes the Company's activity related to asset retirement obligations for the nine month period ended September 30, 2005 and for the year ended December 31, 2004:

	2005	2004
	(in thousands)	
Asset retirement obligation at January 1	$ 8,565	$ 7,544
Accretion of discount	244	314
Obligations incurred	277	804
Obligations settled/removed	(1,489)	(134)
Revisions of estimates	(10)	37
Asset retirement obligation at September 30, 2005 and December 31, 2004	$ 7,587	$ 8,565
Current liability	342	473
Long-term liability	7,245	8,092
Asset retirement obligation at September 30, 2005 and December 31, 2004	$ 7,587	$ 8,565

For the nine months ended September 30, 2005, the obligations settled/removed includes $0.8 million of obligations removed due to the sale of oil and gas properties. The liability for the plugging and abandonment of these properties was assumed by the buyer.

(13) NEW PRONOUNCEMENTS

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

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

Based upon SEC rules issued in April 2005, FAS 123 (Revised 2004) is effective for fiscal years that begin after June 15, 2005 and will be adopted by the Company in the first quarter of 2006. See Note 10 of these financial statements for a disclosure of the effect of net income and earnings per share for the three and nine month periods ended September 30, 2005 and 2004 if the Company had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

In March 2005, the FASB issued Interpretation No. 47 ("FIN 47"), "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143". FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value can be reasonably estimated. FIN 47 states that a conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional upon a future event that may or may not be within control of the entity. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The Company does not expect the adoption of FIN 47 to have a material impact on its financial position or results of operations.

In May 2005, the Financial Accounting Standards Board (“FASB”) issued Statement of Accounting Standards (“SFAS”) No. 154 “Accounting Changes and Error Corrections.” SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle and requires retrospective applications to prior periods’ financial statements of a voluntary change in accounting principle unless it is impracticable. This new accounting standard is effective for fiscal years beginning after December 15, 2005.

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

The following updates information as to Southwestern Energy Company's financial condition provided in our 2004 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2005 and the comparable periods of 2004. For definitions of commonly used gas and oil terms used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2004 Annual Report on Form 10-K.

This Form 10-Q contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in "Risk Factors" and elsewhere in our 2004 Annual Report on Form 10-K. You should read the following discussion with our financial statements and related notes included in this Form 10-Q. All historical per share information in the financial statements, footnotes and Management's Discussion and Analysis of Financial Condition and Results of Operations have been adjusted to reflect the two-for-one stock split effected on June 3, 2005.

OVERVIEW

Southwestern Energy Company is a growing integrated energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We are also focused on creating and capturing additional value at and beyond the wellhead through our natural gas distribution systems and our marketing business. Our marketing business has recently been expanded to include our gas gathering activities relating to our Fayetteville Shale resource play and is now referred to as Midstream Services. All of our operations are located within the United States and we operate principally in three segments: Exploration and Production (or E&P), Natural Gas Distribution and Midstream Services.

Our E&P business has increasingly contributed to our financial results primarily due to the general increase in natural gas and crude oil commodity prices and the growth in our production volumes. For the three months ended September 30, 2005, 100% of our operating income was generated by our E&P and Midstream Services segments, as compared to 96% for the comparable period in 2004. Our natural gas distribution segment generated a seasonal loss for the third quarter of 2005 and 2004. For the first nine months of 2005, 97% of our operating income was generated by our E&P segment, with our Natural Gas Distribution segment generating 1% and our Midstream Services and other businesses generating 2%, as compared to 90%, 4% and 6%, respectively, for the comparable period in 2004. For fiscal year 2004, 90% of our operating income was generated by our E&P segment, with our natural gas distribution generating 5% and our Midstream Services and other businesses also generating 5%.

We operate our E&P business in four general regions—the Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. Currently our E&P activities in the Arkoma Basin and East Texas generate the majority of our production and proved reserves, accounting for 37% and 41% of production and 38% and 47% of our proved reserves, respectively, in 2004. If we continue to be successful in the development of our Fayetteville Shale play, an unconventional shale gas play on the Arkansas side of the Arkoma Basin, we expect the production and proved reserves generated by our activities in the Arkoma Basin to significantly increase over the next several years.

Our natural gas production has increasingly generated a substantial portion of our total operating revenues as a result of the natural gas focus of our capital investments in the past three years. For the three months ended September 30, 2005, sales of natural gas production accounted for 92% of total operating revenues for the E&P segment as compared with 93% for the comparable period in 2004. For the first nine months of 2005, sales of natural gas production accounted for 91% of total operating revenues for the E&P segment as compared with 92% for the comparable period in 2004.

We currently derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. There has been significant price volatility in the natural gas and crude oil market in recent years due to a variety of factors we cannot control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas. In addition, the price we realize for our gas production is affected by our hedging activities as well as locational differences in market prices. Our ability to increase our natural gas production is dependent upon our ability to economically find and produce natural gas, our ability to control costs, and our ability to market natural gas on economically attractive terms to our customers.

Recent Developments

- *Successful Follow-on Equity Offering.* In September 2005, we offered and sold 9,775,000 shares of our common stock at a price per share of $61.35 in connection with an underwritten offering. The net proceeds of the offering were approximately $580 million, after underwriting discounts and expenses.

- *Increase in 2005 Capital Expenditures.* In early September 2005, we announced our intent to increase our 2005 capital budget to $499.5 million, up from the $438.8 million capital program announced in July of this year. The increased amount includes projected capital expenditures of approximately $485.8 million for our E&P and Midstream Services segments, up from $425.1 million. Of the $60.7 million increase in capital expenditures:
    - approximately $21.0 million is related to the 2005 portion of the estimated cost of fabricating five additional land drilling rigs;
    - approximately $15.7 million is allocated to the development of gathering systems related to our Fayetteville Shale play in Arkansas;
    - approximately $7.9 million is being allocated to fund activities in East Texas;
    - approximately $5.2 million is allocated to our Fayetteville Shale play for additional development drilling and leasehold acquisition costs; and
    - approximately $10.9 million is related to New Ventures and other exploration and development activities.

- *Purchase of Additional Drilling Rigs.* In late September 2005, we announced that we had entered into an agreement to fabricate five additional land drilling rigs for an aggregate purchase price of $40.7 million. Including required ancillary equipment and supplies, the total cost for the additional five rigs is approximately $49.2 million. In connection with entering the agreement, we deposited into escrow approximately $10.2 million as a down payment. An additional $10.2 million is required to be deposited into escrow upon notification of commencement of fabrication of the first of the five rigs.

– *Two-for-One Stock Split.* In October 2005, our Board of Directors declared a two-for-one stock split. The additional shares will be distributed November 17, 2005 to shareholders of record as of November 3, 2005.

Three Months Ended September 30, 2005 Compared with Three Months Ended September 30, 2004

Our revenues for the third quarter of 2005 were approximately 46% higher than the comparable period in 2004 due primarily to higher market-driven commodity prices realized for our gas and oil sales. We reported net income of $39.5 million, or $0.51 per share on a diluted basis, on revenues of $162.1 million for the three months ended September 30, 2005, compared to $25.4 million, or $0.34 per share, on revenues of $111.4 million for the same period in 2004. Operating income for our E&P segment was $68.9 million for the quarter ended September 30, 2005, up from $43.1 million for the same period in 2004. The increases in our net income and in the operating income for the E&P segment were primarily due to a 8% increase in production volumes and higher realized natural gas and oil prices, which were partially offset by an increase in our operating costs and expenses. Our gas distribution segment incurred a seasonal operating loss of $3.2 million for the three months ended September 30, 2005, compared to a loss of $2.7 million for the same period in 2004. The decrease in operating income for our gas distribution segment resulted primarily from increased operating costs and expenses.

In the third quarter of 2005, our gas and oil production increased to 16.2 Bcfe, up from 15.0 Bcfe in the third quarter of 2004. The increase in 2005 production primarily resulted from an increase in production from our Overton Field in East Texas and increased production in the Arkoma Basin.

Our capital investments totaled $154.2 million for the third quarter of 2005, up from $90.9 million in the third quarter of 2004. We invested $146.0 million in our E&P segment in the third quarter of 2005, compared to $87.7 million for the same period in 2004.

Nine Months Ended September 30, 2005 Compared with Nine Months Ended September 30, 2004

Net income for the nine months ended September 30, 2005 was $98.9 million, or $1.31 per share on a diluted basis, on revenues of $455.6 million, compared to net income of $70.7 million, or $0.96 per share, on revenues of $327.6 million for the same period in 2004. Operating income for our E&P segment was $165.2 million for the first nine months of 2005, up from $114.0 million for the same period in 2004. The increases were due to increased production volumes and higher prices realized for our production. Operating income for our gas distribution segment was $1.9 million for the first nine months of 2005, compared to $4.7 million for the same period in 2004. The decrease in operating income for our gas distribution segment resulted primarily from increased operating costs and expenses. Our cash flow from operating activities was $215.8 million for the nine months ended September 30, 2005, compared to $183.3 million for the same period in 2004. The increase in operating cash flow was primarily due to the improved operating results of our E&P segment.

In the first nine months of 2005, our gas and oil production increased to 45.2 Bcfe, up from 39.0 Bcfe in the same period of 2004. The increase in 2005 production primarily resulted from an increase in production from our Overton Field in East Texas and increased production in the Arkoma Basin.

Our capital investments totaled $340.9 million for the first nine months of 2005, up from $217.7 million in the first nine months of 2004. Our cash flow from operating activities funded 63% of our capital investments in the first nine months of 2005, and funded 84% of the capital investments in the first nine months of 2004. We invested $323.3 million in our E&P segment in the first nine months of 2005, compared to $210.7 million for the same period in 2004. As discussed under "Recent Developments" above, in September 2005, we announced an increase in our 2005 capital budget to $499.5 million, up from the $438.8 million capital program announced in July of this year.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2005	2004	2005	2004
Revenues (in thousands)	$114,269	$75,670	$283,852	$200,613
Operating income (in thousands)	$68,861	$43,113	$165,191	$113,994
Gas production (MMcf)	15,030	13,996	41,989	36,293
Oil production (MBbls)	200	164	543	456
Total production (MMcfe)	16,227	14,980	45,246	39,029
Average gas price per Mcf, including hedges	$6.98	$5.04	$6.16	$5.07
Average gas price per Mcf, excluding hedges	$7.89	$5.49	$6.74	$5.55
Average oil price per Bbl, including hedges	$47.23	$31.21	$42.29	$29.51
Average oil price per Bbl, excluding hedges	$61.07	$42.78	$53.36	$38.07
Average unit costs per Mcfe				
Lease operating expenses	$0.51	$0.38	$0.46	$0.38
General & administrative expenses	$0.42	$0.33	$0.40	$0.35
Taxes, other than income taxes	$0.40	$0.24	$0.35	$0.26
Full cost pool amortization	$1.44	$1.19	$1.37	$1.19

Revenues. Revenues for our E&P segment were up 51% to $114.3 million for the three months ended September 30, 2005 and up 41% to $283.9 million for the nine months ended September 30, 2005, as compared to the comparable periods in 2004. The increases were primarily due to increased production volumes and higher gas and oil prices realized for our production. Revenues for the first nine months of 2005 and 2004 also include pre-tax gains of $2.1 million and $3.0 million, respectively, related to the sale of gas in storage inventory.

Operating Income. Operating income for the E&P segment was up 60% to $68.9 million for the third quarter of 2005 and up 45% to $165.2 million for the first nine months of 2005, as compared to the respective periods in 2004. The increase in operating income resulted from the increase in revenues, as discussed above, partially offset by increased operating costs and expenses.

Production. Gas and oil production during the third quarter of 2005 was 16.2 Bcfe, up 8% from 15.0 Bcfe in the third quarter of 2004. Gas and oil production was 45.2 Bcf equivalent for the first nine months of 2005, compared to 39.0 Bcf equivalent for the same period of 2004. The comparative increase in production primarily resulted from an increase in production from our Overton Field in East Texas and increased production in the Arkoma Basin. Production during the first nine months of 2005 included the effects of curtailment of a portion of our production at our Overton Field due to pipeline repairs of a non-operated transmission line into which we deliver a large portion of our gas production. Gas production was 15.0 Bcf for the third quarter of 2005 up from 14.0 Bcf for the third quarter of 2004. Gas production was 42.0 Bcf for the first nine months of 2005 compared to 36.3 Bcf for the same period of 2004. Our oil production was 200 MBbls during the third quarter of 2005 and 543 MBbls for the first nine months of 2005, up from 164 MBbls and 456 MBbls for the same periods of 2004, respectively.

In August 2005, Hurricane Katrina struck the Gulf Coast and in September 2005, Hurricane Rita made landfall along the Louisiana and the eastern Texas coasts. There was no significant reduction in our production from our Gulf Coast operations as a result of the two hurricanes.

Average Realized Prices. The average price realized for our gas production, including the effect of hedges, was $6.98 per Mcf for the three months ended September 30, 2005, up from $5.04 per Mcf for the same period of 2004. For the first nine months of 2005, we received an average gas price of $6.16 compared to $5.07 for the same period of 2004. The change in the average prices realized primarily reflects changes in average spot market prices and the effects of our price hedging activities. Our hedging activities decreased the average gas price realized during the third quarter of 2005 by $0.91 per Mcf compared to $0.45 per Mcf for the same period of 2004. Our hedging activities decreased the average gas price realized by $0.58 per Mcf for the first nine months of 2005, compared to a decrease of $0.48 per Mcf during the same period of 2004. Locational differences in market prices for natural gas have continued to be wider than historically experienced and were exceptionally wide at the end of the third quarter, which will affect our fourth quarter results of operations. Disregarding the impact of hedges, the average price received for our gas production during the third quarter of 2005 was approximately $0.60 lower than average NYMEX spot prices, compared to the average for the prior year period of approximately $0.27 per Mcf. The average price received for our gas production during the first nine months of 2005 was approximately $0.42 lower than average NYMEX spot prices, compared to the average for the prior year period of approximately $0.26 per Mcf. In the third quarter of 2005, a loss associated with the ineffectiveness of our cash flow hedges was more than offset by a gain on our basis hedges that do not qualify as cash flow hedges resulting in a net gain of $8.7 million and increasing our average gas price realized in the third quarter of 2005 by $0.58 per Mcf.

We realized an average price of $42.29 per barrel for our oil production, including the effect of hedges, during the nine months ended September 30, 2005, up from $29.51 per barrel for the same period of 2004. The average price we received for our oil production in the first nine months of 2005 and 2004 was reduced by $11.07 per barrel and $8.56 per barrel, respectively, due to the effects of our hedging activities.

Hedging Activities. We periodically enter into hedging activities with respect to a portion of our projected natural gas and crude oil production through a variety of financial arrangements intended to support natural gas and oil prices at targeted levels and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. For the remainder of 2005, we have hedges in place for 11.1 Bcf of gas production and for 2006 and 2007 we have 49.9 Bcf and 38.0 Bcf, respectively, of our future gas production hedged. For the remainder of 2005, we have hedged 90 MBbls of our oil production at an average NYMEX price of $33.17 per barrel. For 2006 we have hedged 120 MBbls of our future oil production. Additionally, we have basis hedges on 9.3 Bcf for the remainder of 2005, 25.3 Bcf for 2006 and 10.0 Bcf for 2007. These basis hedges do not qualify as cash flow hedges, therefore any changes in the fair market valuation of these hedges are immediately recognized as income or loss. For additional information regarding our commodity price risk hedging activities, we refer you to Part I, Item 3 of this Form 10-Q.

Lease Operating Expenses. Lease operating expenses per Mcfe for our E&P segment were $0.51 and $0.46 for the third quarter and first nine months of 2005, respectively, compared to $0.38 for both the third quarter and first nine months of 2004. The increases in lease operating expenses per Mcfe for the third quarter and first nine months of 2005, as compared to the prior year, primarily resulted from increases in compression, saltwater disposal and gas processing costs as well as generally higher oil field service costs.

General & Administrative Expenses. General and administrative expenses per Mcfe were $0.42 for the third quarter of 2005 and $0.40 for the nine months ended September 30, 2005, compared to $0.33 and $0.35 for the same periods of 2004. General and administrative expenses for our E&P segment increased to $18.2 million for the first nine months of 2005, compared to $13.8 million for the same period of 2004 due primarily to increased compensation costs associated with increased staffing levels.

Taxes Other Than Income Taxes. Taxes other than income taxes per Mcfe were $0.40 for the third quarter of 2005 and $0.35 for the nine months ended September 30, 2005, compared to $0.24 and $0.26 for the comparable periods in 2004. The increase in severance taxes per Mcfe in 2005 is primarily due to comparatively higher average market prices in effect for natural gas and crude oil, as reflected in the average price received for our production excluding the effect of hedges.

Full Cost Pool Amortization. Our full cost pool amortization rate was $1.44 per Mcfe for the third quarter of 2005 and $1.37 for the first nine months of 2005, compared to $1.19 per Mcfe for the same periods in 2004. The increase in our full cost pool amortization rate was primarily due to increased finding and development costs. We currently expect our full cost pool amortization rate to average between $1.40 and $1.45 per Mcfe for 2005. Depreciation, depletion and amortization expense for our E&P segment increased to $63.6 million for the first nine months of 2005, compared to $47.6 million for the same period of 2004 as a result of the 16% increase in our production volumes and the increase in the per unit rate of amortization.

Full Cost Pool Ceiling. We utilize the full cost method of accounting for capitalizing costs related to our natural gas and oil properties. As discussed in Note 3 to the financial statements, these capitalized costs are subject to a ceiling test that limits our pooled costs and requires us to write-off costs in excess of the ceiling as a non-cash expense. At September 30, 2005, our standardized measure was calculated based upon the latest quoted market prices of $15.22 per Mcf for Henry Hub gas and $66.24 per barrel for West Texas Intermediate oil, adjusted for market differentials. The price for Henry Hub gas is based upon reported prices for September 26, 2005, which was the last reported date for Henry Hub gas due to Hurricane Rita. A significant decline in natural gas and oil prices from above-referenced levels or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

Natural Gas Distribution

	For the three months ended September 30,		For the nine months ended September 30,	
	2005	2004	2005	2004
Revenues (in thousands)	$20,266	$18,170	$107,450	$102,441
Gas purchases (in thousands)	$11,154	$9,188	$67,886	$63,529
Operating costs and expenses (in thousands)	$12,313	$11,672	$37,679	$34,220
Operating income (loss) (in thousands)	($3,201)	($2,690)	$1,885	$4,692
Deliveries to sales and end-use transportation customers (Bcf)	3.0	3.2	16.0	16.8
Customers at period-end	142,642	139,631	142,642	139,631
Average sales rate per Mcf	$15.85	$12.18	$10.63	$9.18
Heating weather - degree days	14	18	2,231	2,340
Percent of normal	33%	43%	90%	94%

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, 2005 increased 12% and 5%, respectively, from the comparable periods of 2004 due to higher gas prices, partially offset by lower volumes delivered to customers.

Operating Income. Operating income for our gas distribution segment decreased by approximately $0.5 million in the third quarter of 2005 and by approximately $2.8 million for the first nine months of 2005, compared to comparable periods of 2004, due to decreased deliveries caused by warmer weather and increased operating costs and expenses. Weather during the first nine months of 2005 was 10% warmer than normal and 4% warmer than the same period in 2004.

Deliveries. The utility systems delivered 3.0 Bcf and 16.0 Bcf to sales and end-use transportation customers during the three- and nine-month periods ended September 30, 2005, compared to 3.2 Bcf and 16.8 Bcf for the same periods in 2004. The decrease in deliveries during the first nine months of 2005 was primarily due to the effects of warmer weather and continued customer conservation brought about by high gas prices.

Rates. Our utility's tariffs contain a weather normalization clause intended to lessen the impacts of revenue increases and decreases that might result from weather variations during the winter heating season. The increase in gas costs in the first nine months of 2005 was reflected in the utility segment's average rate for its sales which increased to $10.63 per Mcf, up from $9.18 per Mcf for the same period in 2004. The fluctuations in the average sales rate primarily reflect changes in the average cost of gas purchased for delivery to our customers, which are passed through to customers under automatic adjustment clauses. Our latest request for a rate increase was heard by the Arkansas Public Service Commission (APSC) at a September 20-22, 2005 public hearing in Little Rock, Arkansas. The APSC has until October 28, 2005 to reach its decision regarding our request.

Hedging Activities. Our utility segment hedged 2.9 Bcf of gas purchases in the first nine months of 2005 which had the effect of increasing its total gas supply cost by $1.4 million. In the first nine months of 2004, our utility hedged 3.8 Bcf of its gas supply which decreased its total gas supply cost by $0.1 million. At September 30, 2005, we had 1.1 Bcf of future gas purchases hedged at an average purchase price of $13.03 per Mcf. We entered into additional hedges on 1.0 Bcf of future gas purchases at an average price of $13.80 per Mcf subsequent to the end of the quarter. For additional information regarding our commodity price risk hedging activities, we refer you to Part I, Item 3 of this Form 10-Q.

Operating Costs and Expenses. The changes in purchased gas costs for our gas distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from various gas supply contracts (base load, swing and no-notice). Other operating costs and expenses for this segment were higher during the third quarter than the comparable period of the prior year due primarily to higher operating expenses. For the first nine months of 2005, other operating costs and expenses were higher than the comparable period of the prior year due primarily to higher operating expenses and general and administrative expenses. The increases in operating expense in 2005 were due to an increase in uncollectible accounts, fuel and labor costs. The increase in general and administrative expense primarily resulted from increased compensation costs.

Midstream Services

	For the three months ended September 30,		For the nine months ended September 30,	
	2005	2004	2005	2004
Revenues (in thousands)	$133,612	$85,050	$304,979	$218,745
Operating income (in thousands)	$1,520	$712	$3,488	$2,410
Gas volumes marketed (Bcf)	17.1	15.9	46.5	41.3

Revenues. Revenues from our natural gas gathering and marketing activities, or Midstream Services, were $133.6 million and $305.0 million for the three- and nine-month periods ended September 30, 2005, compared to $85.0 million and $218.7 million for the comparable periods of 2004. The increase in revenues from this segment is attributable to increased volumes marketed and an increase in natural gas commodity prices. The increase in revenues was largely offset by a comparable increase in purchased gas costs. Gathering revenues have been insignificant to-date but could increase in the future depending upon the level of production from our Fayetteville Shale area.

Operating Income. Our operating income from Midstream Services was $1.5 million for the third quarter of 2005 and $3.5 million for the first nine months of 2005, compared to $0.7 million and $2.4 million for the comparable periods of 2004. Operating income from natural gas marketing fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity.

Gas Volumes Marketed. We marketed 13.8 Bcf of affiliated gas in the third quarter of 2005, representing 81% of total volumes marketed, compared to 12.5 Bcf, or 79% of total volumes marketed, for the same period in 2004. Affiliated gas marketed for the first nine months of 2005 was 35.5 Bcf compared to 32.6 Bcf for the same period in 2004. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Item 3, "Qualitative and Quantitative Disclosure about Market Risks" in this Form 10-Q for additional information.

Transportation

We recorded pre-tax income from operations related to our investment in the NOARK Pipeline System Limited Partnership (NOARK) of $0.1 million for the third quarter of 2005 and $0.4 million for the first nine months of 2005, compared to pre-tax losses of $0.6 million and $1.1 million for the comparable periods of 2004. These amounts were recorded in other income (expense) in our statements of operations.

In September 2005, Enogex announced that it had entered into an agreement to sell the subsidiary that holds its 75% interest in NOARK to Atlas Pipeline Partners, L.P., subject to regulatory review and customary closing conditions. Enogex stated that a portion of the sale proceeds will be used to redeem their 40% share of the 7.15% Notes due 2018.

Interest Expense

Interest costs, net of capitalization, increased 12% for the third quarter of 2005 and 11% for the first nine months of 2005, as compared to the same periods of 2004. The increase in interest costs in 2005 resulted from higher average borrowings during the period at higher interest rates. Changes in capitalized interest are primarily due to the level of costs excluded from amortization in our E&P segment and to our investment in drilling rigs under construction.

Income Taxes

Our effective tax rate was approximately 37% for the three- and nine-month periods ended September 30, 2005 and 2004. The changes in the provision for deferred income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences.

Pension Expense

We recorded pension expense of $0.6 million in the third quarters of both 2005 and 2004, and $1.7 million for the first nine months of 2005 and 2004, respectively. The amount of pension expense recorded by us is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $1.8 million to our pension plans in 2005, all of which had been contributed as of September 30, 2005. For further information regarding our pension plans, we refer you to Note 10 of the financial statements in this Form 10-Q.

New Accounting Principles

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

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

Based upon SEC rules issued in April 2005, FAS 123 (Revised 2004) is effective for fiscal years that begin after June 15, 2005 and will be adopted by us in the first quarter of 2006. In Note 10 of the financial statements included in this Form 10-Q, we disclose the effect on net income and earnings per share for the three- and nine-month periods ended September 30, 2005 and 2004 if we had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

In March 2005, the FASB issued Interpretation No. 47 ("FIN 47"), "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143". FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value can be reasonably estimated. FIN 47 states that a conditional asset retirement obligation is a legal obligation to perform an asset retirement activity in which the timing or method of settlement are conditional upon a future event that may or may not be within control of the entity. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. We do not expect the adoption of FIN 47 to have a material impact on our financial position or results of operations.

In May 2005, the Financial Accounting Standards Board ("FASB") issued Statement of Accounting Standards ("SFAS") No. 154 "Accounting Changes and Error Corrections." SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle and requires retrospective applications to prior periods' financial statements of a voluntary change in accounting principle unless it is impracticable. This new accounting standard is effective for fiscal years beginning after December 15, 2005.

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds, our unsecured revolving credit facility (discussed below under "Financing Requirements") and funds accessed through public debt and equity markets as our primary sources of liquidity. We have the ability to borrow up to $500 million under our revolving credit facility from time to time. In September 2005, we consummated an underwritten offering of 9,775,000 shares of our common stock pursuant to an effective registration statement filed with the

Securities and Exchange Commission. The net proceeds of the offering were approximately $580.0 million after deduction of the underwriting discounts and offering expenses. Approximately $193.0 million was used to pay down outstanding indebtedness under the Company's revolving credit facility and the remainder was invested in short-term marketable securities. As of September 30, 2005, there were no amounts outstanding under our revolving credit facility. The remainder of our capital expenditures for 2005 will be funded by our cash flow from operations and the proceeds from the recent equity offering.

Net cash provided by operating activities was $215.8 million in the first nine months of 2005, compared to $183.3 million for the same period of 2004. Net cash provided by operating activities primarily consists of net income adjusted for depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. For the first nine months of 2005 and 2004, cash provided by operating activities provided 63% and 84%, respectively, of our requirements for capital expenditures.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our gas production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 6 to the financial statements included in this Form 10-Q and Item 3, "Quantitative and Qualitative Disclosures about Market Risks." Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Expenditures

Our capital expenditures for the first nine months of 2005 were $340.9 million, including $24.8 million relating to the effects of accrued expenditures, compared to $217.7 million for the same period in 2004 including $6.4 million relating to the change in the amount of accrued expenditures. In September 2005, we announced our intent to increase in our 2005 capital budget to $499.5 million, up from the $438.8 million capital program announced in July of this year. Of the $60.7 million increase in capital expenditures, approximately $21.0 million related to the 2005 portion of the estimated cost of fabricating five additional new land drilling rigs; $15.7 million is allocated to the development of a gas gathering system related to our Fayetteville Shale play in Arkansas; approximately $7.9 million is being allocated to fund activities in East Texas; approximately $5.9 million is allocated to New Ventures and other Exploration; approximately $5.2 is allocated to our Fayetteville Shale play for additional development drilling and additional leasehold acquisition costs; and approximately $5.0 million is related to our shallow oil drilling program in Eddy County, New Mexico. Our 2005 capital investment program is expected to be funded through cash flow from operations, borrowings under our revolving credit facility and the proceeds from our recent equity offering.

Financing Requirements

Our total debt outstanding was $225.0 million at September 30, 2005 and $325.0 million at December 31, 2004. The total debt at September 30, 2005 included $125.0 million of 6.70% senior notes due December 2005, which we will repay using the proceeds from our equity offering. These notes are recorded as a current liability at September 30, 2005. There were no amounts outstanding under our revolving credit facility at September 30, 2005. In January 2005, we amended and restated our previous $300 million revolving credit facility due to expire in January 2007, increasing the borrowing capacity to $500 million and extending the expiration to January 2010. The amended and restated credit facility also replaced another smaller credit facility. The interest rate on the new facility is calculated based upon our debt rating and is currently 125 basis points over the current London Interbank Offered Rate (LIBOR). Our publicly traded notes are rated Ba2 by Moody's and BBB- by Standard & Poor's, following a downgrade from BBB in January 2005. Any future downgrades in our public debt ratings could increase the cost of funds under our revolving credit facility.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreements, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. EBITDA is a measure required by our debt covenants and is defined as net income plus interest expense, income tax expense, and depreciation, depletion and amortization. Additionally, there are also restrictions on the ability of our subsidiaries to incur debt. We were in compliance with the covenants of our debt agreements at September 30, 2005. Although we do not anticipate any debt covenant violations, our ability to comply with our credit agreement is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our credit facility, we would have to decrease our capital expenditure plans.

At September 30, 2005, our capital structure consisted of 19% debt (excluding our several guarantee of NOARK's obligations) and 81% equity, with a ratio of EBITDA to interest expense of 17.4. Shareholders' equity in the September 30, 2005 balance sheet includes an accumulated other comprehensive loss of $171.1 million related to our hedging activities that is required to be recorded under the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). This amount is based on the market value of our hedges as of September 30, 2005, and does not necessarily reflect the value that we will receive or pay when the hedges ultimately are settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our debt covenants as to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 as well as the non-cash impact of any full cost ceiling write-downs, and include the guarantee of NOARK's obligations. Our capital structure, including $39.6 million relating to our several guarantee of NOARK's obligations, would be 19% debt and 81% equity at September 30, 2005, without consideration of the accumulated other comprehensive loss related to FAS 133 of $171.1 million.

As part of our strategy to insure a certain level of cash flow to fund our operations, we have hedged approximately 70% to 80% of our expected 2005 gas production and 60% to 70% of our expected 2005 oil production.

Off-Balance Sheet Arrangements

We hold a 25% general partnership interest in NOARK, which owns the Ozark Pipeline that is utilized to transport our gas production and the gas production of others. We account for our investment under the equity method of accounting. We and the other general partner of NOARK, Enogex, Inc. ("Enogex"), have severally guaranteed the principal and interest payments on NOARK's 7.15% Notes due 2018. The notes were issued in June 1998 to partially finance the original construction cost of the NOARK Pipeline. Our share of the guarantee is 60% and we are allocated 60% of the interest expense. At September 30, 2005, the outstanding principal amount of these notes was $66.0 million and our share of the guarantee was $39.6 million. The notes require semi-annual principal payments of $1.0 million. Under the several guarantee, we are required to fund our share of NOARK's debt service which is not funded by operations of the pipeline. We were not required to advance any funds to NOARK in the first nine months of 2005 and 2004. We do not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

Our share of the results of operations included in other income (expense) related to our NOARK investment was pre-tax income of $0.1 million for the third quarter of 2005 and $0.4 million for the first nine months of 2005, compared to pre-tax losses of $0.6 million and $1.1 million for the comparable periods of 2004.

In September 2005, Enogex announced that it had entered into an agreement to sell the subsidiary that holds its 75% interest in NOARK to Atlas Pipeline Partners, L.P., subject to regulatory review and customary closing conditions. Enogex stated that a portion of the sale proceeds will be used to redeem their 40% share of the 7.15% Notes due 2018.

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, 2005 were as follows:

Contractual Obligations

		Payments Due by Period			
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
Senior notes	$225,000	$125,000	$ -	$60,000	$ 40,000
Interest on senior notes[1]	52,441	8,878	14,918	8,449	20,196
Operating leases[2]	9,790	1,796	3,495	3,157	1,342
Unconditional purchase obligations[3]	-	-	-	-	-
Demand charges[4]	98,507	14,383	19,362	20,551	44,211
Drilling rigs[5]	59,542	59,542	-	-	-
Other obligations[6]	4,313	4,263	50	-	-
	$449,593	$213,862	$37,825	$92,157	$105,749

(1) Interest on senior notes includes interest on the $60 million notes that are due in 2027 and putable at the holder's option in 2009.

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

(3) Our utility segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at September 30, 2005 totaled 1.2 Bcf, comprised of 0.7 Bcf in less than one year, 0.3 Bcf in one to three years, and 0.2 Bcf in three to five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.

(4) Our utility segment has commitments for approximately $92.0 million of demand charges on non-cancelable firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has a commitment for approximately $6.5 million of demand transportation charges.

(5) Our E&P segment has commitments for approximately $59.5 million related to the purchase of ten drilling rigs expected to be delivered within the next year.

(6) Our significant other contractual obligations include approximately $1.1 million for funding of benefit plans, approximately $1.2 million of various information technology support and data subscription agreements, approximately $1.0 million for drilling rig commitments, and approximately $0.3 million of land leases.

We refer you to Note 5 of the financial statements for a discussion of the terms of our debt.

In July 2005, we announced that we had entered into an agreement to fabricate five new land drilling rigs for an aggregate purchase price of $37.7 million. The agreement calls for payments totaling $27.7 million during 2005, with the remainder due in early 2006.

On September 29, 2005, the Company entered into an agreement to fabricate an additional five new land drilling rigs for an aggregate purchase price of $40.7 million. Scheduled payments under this agreement are $10.2 million in 2005 and $30.5 million in 2006.

Contingent Liabilities or Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. As a result of actuarial data, we expect to record pension expense of approximately $2.3 million in 2005, $1.7 million of which has been recorded in the first nine months of 2005. For further information regarding our pension plans, we refer you to Note 11 of the financial statements in this Form 10-Q. In addition, as discussed above in "Off-Balance Sheet Arrangements," we have guaranteed 60% of the principal and interest payments on NOARK's 7.15% Notes due 2018. At September 30, 2005 the outstanding principal of these notes was $66.0 million and our share of the guarantee was $39.6 million. The notes require semi-annual principal payments of $1.0 million. The foregoing obligations represent commitments and contingencies that could create, increase or accelerate our liabilities.

We are subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to our Boure prospect in Louisiana. The allegations were contested and, in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. We are pursuing this decision to the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our above-described credit facility. We had positive working capital of $143.4 million at September 30, 2005, including $387.0 million of marketable securities and current notes payable of $125.0 million, compared to negative working capital of $2.7 million at December 31, 2004. At September 30, 2005, we also had $500.0 million of available borrowing capacity under our revolving credit facility. Our current assets increased by 372% in the first nine months of 2005 while current liabilities increased 255% compared to December 31, 2004. The change in working capital from December 31, 2004 to September 30, 2005 primarily is the result of the receipt of the proceeds from our equity offering, the investment of a portion of those proceeds in short-term marketable securities and our intention to use a portion of the proceeds to repay $125 million of notes.

Gas in Underground Storage

We record our gas stored in inventory owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 8.7 Bcf at $3.72 at September 30, 2005 and 9.3 Bcf at $3.49 at December 31, 2004.

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

* the timing and extent of changes in commodity prices for natural gas and oil;
* the timing and extent of our success in discovering, developing, producing and estimating reserves;
* the extent to which the Fayetteville Shale play can replicate the results of other productive shale gas plays;
* the potential for significant variability in reservoir characteristics of the Fayetteville Shale over such a large acreage position;
* the extent of our success in drilling and completing horizontal wells;
* our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
* our lack of experience owning and operating drilling rigs;
* our ability to fund our planned capital expenditures;
* our future property acquisition or divestiture activities;
* the effects of weather and regulation on our gas distribution segment;
* increased competition;
* the impact of federal, state and local government regulation;
* the financial impact of accounting regulations and critical accounting policies;
* changing market conditions and prices (including regional basis differentials);
* the comparative cost of alternative fuels;
* conditions in capital markets and changes in interest rates;
* the availability of oil field personnel, services, drilling rigs and other equipment; and
* any other factors listed in the reports we have filed and may file with the SEC.

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

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

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounted for greater than 6% of accounts receivable at September 30, 2005. See the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

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

Commodities Risk

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

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

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for our gas and oil production, gas purchases and marketing activities. The table presents the notional amount in Bcf and MBbls, the weighted average contract prices, and the fair value by expected maturity dates. At September 30, 2005, the fair value of these financial instruments was a $264.2 million liability.

	Expected Maturity Date		
	2005	2006	2007
Production and Marketing			
Natural Gas			
Swaps with a fixed price receipt			
Contract volume (Bcf)	4.1	7.9	12.0
Weighted average price per Mcf	$5.24	$6.64	$6.66
Fair value (in millions)	($36.3)	($39.6)	($32.5)
Price collars			
Contract volume (Bcf)	7.0	42.0	26.0
Weighted average floor price per Mcf	$4.64	$5.36	$6.46
Fair value of floor (in millions)	-	$.4	$3.2
Weighted average ceiling price per Mcf	$7.71	$9.87	$11.12
Fair value of ceiling (in millions)	($41.6)	($110.4)	($25.3)
Swaps with a fixed price payment			
Contract volume (Bcf)	0.1	-	-
Weighted average price per Mcf	$6.32	-	-
Fair value (in millions)	$0.6	-	-
Oil			
Swaps with a fixed price receipt			
Contract volume (MBbls)	90	120	-
Weighted average price per Bbl	$33.17	$37.30	-
Fair value (in millions)	($3.0)	($3.5)	-
Natural Gas Purchases			
Swaps with a fixed price payment			
Contract volume (Bcf)	.4	.7	
Weighted average price per Mcf	$13.03	$13.03	
Fair Value (in millions)	$0.4	$1.0	

At September 30, 2005, we had outstanding fixed-price basis differential swaps on gas production volumes of 9.3 Bcf in 2005, 25.3 Bcf in 2006, and 10.0 Bcf in 2007 that did not qualify for hedge accounting treatment. The fair value of these differential swaps was an asset of $22.5 million at September 30, 2005. In the third quarter of 2005, we recorded a corresponding gain of $22.3 million related to these differential swaps which was partially offset by a $13.5 million loss related to the estimated ineffectiveness of our cash flow hedges. We entered into additional hedges on 1.0 Bcf of future gas purchases at an average price of $13.80 per Mcf subsequent to the end of the quarter.

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

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

ITEM 4. CONTROLS AND PROCEDURES

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, summarize and report the information that is required to be disclosed or submitted by us within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2005. There were no significant changes in our internal control over financial reporting during the three months ended September 30, 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Company is subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on the Company's financial position or its results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on the Company's financial position and the results of operations for the period in which the effect becomes reasonably estimable. As first reported in the Company's Form 10-Q for the period ended March 31, 2005, a lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure prospect in Louisiana. The allegations were contested and, in 2002, the Company was granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying the Company's motion for summary judgment and granting the motion for summary judgment of the other party. The Company's motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. The Company is pursuing this decision to the Texas Supreme Court. Should the other party prevail on the appeal, the Company could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

ITEM 6. EXHIBITS

(10.1) Purchase and Sale Agreement by and between PV Exploration Company, as Buyer, and M.D. Cowan, as Seller, dated July 1, 2005 for purchase of five drilling rigs.

(10.2) Purchase and Sale Agreement by and between PV Exploration Company, as Buyer, and M.D. Cowan, as Seller, dated September 29, 2005 for purchase of additional five drilling rigs.

(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.

Signatures

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

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: October 27, 2005

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