SOUTHWESTERN ENERGY CO
Form 10-Q
November 07, 2007

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, 2007**

or

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

Commission file number **1-08246**

SOUTHWESTERN ENERGY COMPANY

(Exact name of the registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 N. Sam Houston Pkwy. E., Suite 125, Houston, Texas	**77032**
(Address of principal executive offices)	(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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer X Accelerated filer ___ Non-accelerated filer ___

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 November 5, 2007
Common Stock, Par Value $0.01	170,435,408

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 market conditions and prices for natural gas and oil (including regional basis differentials);

*

the timing and extent of our success in discovering, developing, producing and estimating reserves;

*

the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play, overall as well as relative to other productive shale gas plays;

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our ability to fund our planned capital investments;

*

our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;

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the costs and availability of oil field personnel services and drilling supplies, raw materials, and equipment and services, including pressure pumping equipment and crews in the Arkoma basin;

*

our future property acquisition or divestiture activities;

*

the effects of weather;

*

increased competition;

*

the impact of federal, state and local government regulation;

*

the financial impact of accounting regulations and critical accounting policies;

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the comparative cost of alternative fuels;

*

conditions in capital markets and changes in interest rates, and;

*

any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (SEC).

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in our Annual Report on Form 10-K for the year ended December 31, 2006 (the 2006 Annual Report on Form 10-K), and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q (Form 10-Qs).

Should one or more of the risks or uncertainties described above or elsewhere in our 2006 Annual Report on Form 10-K or the Form 10-Qs 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.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

ASSETS

	September 30, 2007	December 31, 2006
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 615	$ 42,927
Accounts receivable	136,053	131,370
Inventories, at average cost	75,244	62,488
Hedging asset - FAS 133	69,147	64,082
Other	30,094	22,969
Total current assets	311,153	323,836
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $288.8 million in 2007 and $166.8 million in 2006 excluded from amortization	3,692,926	2,651,427
Gas distribution systems	233,005	226,067
Gathering systems	127,714	51,836
Gas in underground storage	32,254	32,254
Other	86,939	77,702
	4,172,838	3,039,286
Less: Accumulated depreciation, depletion and amortization	1,225,527	1,022,786

		2,947,311		2,016,500
Other Assets		34,665		38,733
Total Assets	$	3,293,129	$	2,379,069

The accompanying notes are an integral part of these consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

LIABILITIES AND STOCKHOLDERS' EQUITY

		September 30, 2007		December 31, 2006
		(in thousands)		
Current Liabilities				
Current portion of long-term debt	$	1,200	$	1,200
Accounts payable		333,676		266,023
Taxes payable		12,291		16,088
Advances from partners and customer deposits		37,443		31,941
Hedging liability - FAS 133		8,145		23,864
Over-recovered purchased gas costs		15,214		10,580
Current deferred income taxes		7,004		19,162
Other		14,537		10,002
Total current liabilities		429,510		378,860
Long-Term Debt		730,300		136,600
Other Liabilities				
Deferred income taxes		459,525		370,522
Long-term hedging liability		7,915		4,902
Pension liability		9,938		11,697
Other		34,515		30,811
		511,893		417,932

Commitments and Contingencies				
Minority Interest in Partnership		10,912		11,034
Stockholders' Equity				
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 170,307,333 shares in 2007 and 168,953,893 in 2006		1,703		1,690
Additional paid-in capital		768,312		740,609
Retained earnings		810,399		660,857
Accumulated other comprehensive income		34,752		31,487
Common stock in treasury, at cost, 111,162 shares in 2007		(4,652)		-
		1,610,514		1,434,643
Total Liabilities and Stockholders' Equity	$	3,293,129	$	2,379,069

The accompanying notes are an integral part of these consolidated financial statements.

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

	For the nine months ended September 30,			
		2007		2006
	(in thousands)			
Cash Flows From Operating Activities				
Net income	$	149,542	$	128,876
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization		204,662		101,425
Deferred income taxes		91,654		78,988
Unrealized (gain) loss on derivatives		(2,669)		3,542
Stock-based compensation expense		3,839		4,034

Minority interest in partnership		(122)		(230)
Gain on sale of investment in partnership and other property		-		(10,863)
Equity in income of NOARK partnership		-		(925)
Change in assets and liabilities:				
Accounts receivable		(4,683)		47,468
Inventories		(12,756)		(11,654)
Under/over-recovered purchased gas costs		4,634		(148)
Accounts payable		21,513		(17,506)
Advances from partners and customer deposits		5,501		16,500
Deferred tax benefit - stock options		(17,858)		(7,447)
Other assets and liabilities		(8,239)		(924)
Net cash provided by operating activities		435,018		331,136
Cash Flows From Investing Activities				
Capital investments		(1,139,946)		(603,410)
Proceeds from sale of investment in partnership and other property		5,777		79,655
Other items		383		880
Net cash used in investing activities		(1,133,786)		(522,875)
Cash Flows From Financing Activities				
Debt retirement		(600)		(600)
Payments on revolving long-term debt		(628,050)		-
Borrowings under revolving long-term debt		1,222,350		-
Revolving credit facility amendment costs		(1,275)		-
Excess tax benefit for stock-based compensation		17,858		7,447
Change in bank drafts outstanding		42,013		11,768
Proceeds from exercise of common stock options		4,160		2,540
Net cash provided by financing activities		656,456		21,155
Decrease in cash and cash equivalents		(42,312)		(170,584)
Cash and cash equivalents at beginning of year		42,927		223,705
Cash and cash equivalents at end of period	$	615	$	53,121

The accompanying notes are an integral part of these consolidated financial statements.

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

(Unaudited)

	Common Stock Shares Issued	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Common Stock in Treasury	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)			
Balance at December 31, 2006	168,954	$ 1,690	$ 740,609	$ 660,857	$ -	$ 31,487	$ 1,434,643
Comprehensive income:							
Net income	-	-	-	149,542	-	-	149,542
Change in value of derivatives	-	-	-	-	-	2,830	2,830
Change in value of pension liability	-	-	-	-	-	435	435
Total comprehensive income	-	-	-	-	-	-	152,807
Tax benefit for stock-based compensation	-	-	17,858	-	-	-	17,858
Stock-based compensation - FAS 123(R)	-	-	5,698	-	-	-	5,698
Exercise of stock options	1,339	13	4,147	-	-	-	4,160
Issuance of restricted stock	36	-	-	-	-	-	-
Cancellation of restricted stock	(22)	-	-	-	-	-	-
Treasury stock	-	-	-	-	(4,652)	-	(4,652)
Balance at September 30, 2007	170,307	$ 1,703	$ 768,312	$ 810,399	$ (4,652)	$ 34,752	$ 1,610,514

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	

Net income	$	50,960	$	33,477	$	149,542	$	128,876
Change in value of derivatives								
Current period reclassification to earnings		(16,136)		474		(30,075)		359
Current period ineffectiveness		(870)		(6,396)		3,939		(10,863)
Current period change in derivative instruments		39,782		44,973		28,966		133,667
Total change in value of derivatives		22,776		39,051		2,830		123,163
Current period change in pension liability		435		-		435		-
Comprehensive income, end of period	$	74,171	$	72,528	$	152,807	$	252,039

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries

September 30, 2007

(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, which have been reviewed and approved by the audit committee of the Company s Board of Directors, 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, 2006 (the "2006 Annual Report on Form 10-K").

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GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development, and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural 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 the 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. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At September 30, 2007, the ceiling value of the Company s reserves was calculated based upon quoted market prices of $6.38 per Mcf for Henry Hub gas and $78.25 per barrel for West Texas Intermediate oil, adjusted for market differentials. At September 30, 2007, the Company's unamortized costs of natural gas and oil properties did not exceed this ceiling amount. Cash flow hedges of gas production in place at September 30, 2007 increased the calculated ceiling value by approximately $225.0 million (net of tax). Without the effects of cash flow hedges, the Company s unamortized costs of natural gas and oil properties would have exceeded the ceiling amount. The Company had approximately 174.0 Bcf of future gas production hedged at September 30, 2007. Decreases in market prices from September 30, 2007 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

(3)

EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three and nine months ended September 30, 2007 and 2006, respectively:

	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006

Net Income (in thousands)	$ 50,960	$ 33,477	$ 149,542	$ 128,876
Number of Common Shares:				
Weighted average outstanding	169,795,520	167,514,249	169,292,304	167,114,831
Issued upon assumed exercise of outstanding stock options	2,506,547	3,565,013	2,847,287	3,498,226
Effect of issuance of nonvested restricted common shares	242,045	498,842	223,828	527,456
Weighted average and potential dilutive outstanding (1)	172,544,112	171,578,104	172,363,419	171,140,513
Net Income per Common Share:				
Basic	$ 0.30	$ 0.20	$ 0.88	$ 0.77
Diluted	$ 0.30	$ 0.20	$ 0.87	$ 0.75

(1) Options for 226,473 shares for the nine months ended September 30, 2007 and 220,730 shares for the comparable period of 2006 were excluded from the calculations because they would have had an antidilutive effect. Additionally, 400 shares of restricted stock for the nine months ended September 30, 2007 and 5,535 shares of restricted stock for the comparable period of 2006 were excluded from the calculations because they would have had an antidilutive effect.

(4)

DEBT

Debt balances as of September 30, 2007 and December 31, 2006 consisted of the following:

	September 30, 2007	December 31, 2006
	(in thousands)	
Short-term:		
7.15% Senior Notes due 2018 (current portion)	$ 1,200	$ 1,200
Long-term:		
Variable rate (6.10% at September 30, 2007) unsecured revolving		
credit facility	594,300	-

7.625% Senior Notes due 2027, putable at the holders' option in 2009	60,000	60,000
7.21% Senior Notes due 2017	40,000	40,000
7.15% Senior Notes due 2018	36,000	36,600
Total long-term debt	730,300	136,600
Total debt	$ 731,500	$ 137,800

On October 12, 2007, the Company amended its unsecured revolving credit facility to, among other things, increase the current borrowing capacity to $1.0 billion. Pursuant to the amendment, the amount available under the revolving credit facility may be increased to $1.25 billion at any time upon the Company s agreement with its existing or additional lenders. There was $594.3 million outstanding under the revolving credit facility at September 30, 2007, compared to no amount outstanding at December 31, 2006. The interest rate on the amended credit facility is calculated based upon the Company s debt rating and is currently 87.5 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility is currently guaranteed by the Company s subsidiaries, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The revolving credit facility also 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 stockholders' 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, 2007, the Company s capital structure consisted of 31% debt and 69% equity and it was in compliance with the covenants of its debt agreements.

(5)

DERIVATIVES AND RISK MANAGEMENT

Management enters into various types of derivative instruments for a portion of the Company s projected gas and oil sales to reduce its exposure to market price volatility for natural gas and oil. At September 30, 2007, our gas derivative instruments consisted of price swaps, costless collars and basis swaps. 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, requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Accounting for qualifying hedges allows a derivative's gains and losses to be recorded as a component of other comprehensive income. Hedges that are not elected for hedge accounting treatment or that do not meet the requirement of FAS 133 cannot be recorded as a component of other comprehensive income. The Company s hedging practices are summarized in Note 8 of the Notes to Consolidated Financial Statements of the 2006 Annual Report on Form 10-K.

At September 30, 2007, the Company's net asset recorded on the balance sheet related to its hedging activities was $74.9 million. Additionally, at September 30, 2007, the Company had recorded a gain to other comprehensive income of $44.2 million related to its hedging activities. 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 gas futures as of September 30, 2007 remain unchanged, the Company would expect to transfer an aggregate after-tax gain of approximately $36.1 million from accumulated other comprehensive income to earnings during the next 12 months. The change in accumulated other comprehensive income related to derivatives was a gain of $36.2 million ($22.8 million after tax) compared to a gain of $62.0 million ($39.1 million after tax) for the three months ended September 30, 2007 and 2006, respectively, and a gain of $4.5 million ($2.8 million after tax) compared to a gain of $195.5 million ($123.2 million after tax) for the nine months ended September 30, 2007 and 2006, respectively. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the application of FAS 133.

(6)

SEGMENT INFORMATION

The Company s three reportable business segments, Exploration and Production (E&P), Midstream Services and Natural Gas Distribution, have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced gas volumes and through gathering fees associated with the transportation of natural gas to market. Gathering revenues are expected to increase in the future as the level of production from our Fayetteville Shale properties continues to increase. Revenues for the Natural Gas Distribution segment arise from the transportation and sale of natural gas at retail.

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 of the Notes to Consolidated Financial Statements included in Item 8 of the 2006 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, corporate items and, with respect to the nine months ended September 30, 2006, the Company s former investment in the Ozark Gas Transmission system.

	Exploration And	Midstream Services	Natural Gas	Other	Total

	Production		Distribution		
			(in thousands)		
Three months ended September 30, 2007:					
Revenues from external customers	$ 195,569	$ 84,819	$ 17,234	$ -	$ 297,622
Intersegment revenues	8,561	154,208	20	112	162,901
Operating income (loss)	88,856	4,078	(3,541)	60	89,453
Interest and other income (loss) (1)	299	-	(216)	-	83
Depreciation, depletion and amortization expense	78,279	1,505	1,610	32	81,426
Interest expense (1)	5,483	608	1,173	-	7,264
Provision (benefit) for income taxes (1)	31,766	1,318	(1,873)	22	31,233
Assets	2,838,405	203,649	179,988	71,087 (2)	3,293,129 (2)
Capital investments (3)	381,099	31,115	2,498	1,888	416,600
Three months ended September 30, 2006:					
Revenues from external customers	$ 116,289	$ 33,830	$ 18,275	$ -	$ 168,394
Intersegment revenues	8,483	91,497	20	111	100,111
Operating income (loss)	56,326	1,259	(4,530)	63	53,118
Interest and other income (loss) (1)	1,330	-	(117)	4	1,217
Depreciation, depletion and amortization expense	38,792	174	1,470	23	40,459
Interest expense (1)	190	-	30	-	220
Provision (benefit) for income taxes (1)	21,763	474	(1,776)	57	20,518
Assets	1,818,899	73,937	185,918	101,789 (2)	2,180,543 (2)
Capital investments (3)	233,688	14,727	2,777	7,253	258,445

	Exploration And Production	Midstream Services	Natural Gas Distribution	Other	Total
			(in thousands)		
Nine months ended September 30, 2007:					
Revenues from external customers	$ 515,458	$ 215,217	$ 121,681	$ -	$ 852,356
Intersegment revenues	31,731	436,066	172	336	468,305
Operating income	244,518	6,399	4,134	167	255,218
Interest and other income (loss) (1)	392	-	(420)	7	(21)

Depreciation, depletion and amortization expense	195,392	3,291	4,859	104	203,646
Interest expense (1)	9,122	989	3,617	-	13,728
Provision for income taxes (1)	89,496	2,055	37	66	91,654
Assets	2,838,405	203,649	179,988	71,087 (2)	3,293,129 (2)
Capital investments (3)	1,051,422	76,395	8,441	4,436	1,140,694
Nine months ended September 30, 2006:					
Revenues from external customers	$ 330,969	$ 99,166	$ 118,960	$ -	$ 549,095
Intersegment revenues	29,276	238,295	180	336	268,087
Operating income	186,606	3,128	1,285	197	191,216
Interest and other income (loss) (1)	6,184	-	(312)	11,802	17,674
Depreciation, depletion and amortization expense	95,225	580	4,636	71	100,512
Interest expense (1)	394	-	107	-	501
Provision for income taxes (1)	72,882	1,184	331	4,591	78,988
Assets	1,818,899	73,937	185,918	101,789 (2)	2,180,543 (2)
Capital investments (3)	577,905	30,639	9,108	14,470	632,122

(1)

Interest income, interest expense and the provision (benefit) for income taxes by segment are allocations as they are incurred at the corporate level.

(2)

Other assets include corporate assets not allocated to segments, assets for non-reportable segments and the Company's investment in cash equivalents.

(3)

Capital investments include a reduction of $20.2 million and $2.5 million for the three- and nine-month periods ended September 30, 2007, respectively, and an increase of $11.5 million and $26.8 million for the three- and nine-month periods ended September 30, 2006, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $133.7 million and $77.7 million for the third quarters of 2007 and 2006, respectively, and $382.8 million and $200.3 million for the nine months ended September 30, 2007 and 2006, respectively, for marketing of the Company's E&P sales. Intersegment sales by the E&P segment and Midstream Services segment to the Natural Gas Distribution segment are priced in accordance with the terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures and prepaid costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(7)

INTEREST AND INCOME TAXES PAID

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

	For the nine months ended September 30, 2007		For the nine months ended September 30, 2006	
	(in thousands)			
Interest payments	$	19,141	$	5,825
Income tax payments	$	-	$	6

(8)

CONTINGENCIES AND COMMITMENTS

Operating Commitments

The Company has various operating commitments in the normal course of its operations. The Company has not made any new material operating commitments or modified its disclosed material commitments other than as disclosed in the 2006 Annual Report on Form 10-K and the Form 10-Q for the period ended June 30, 2007.

Environmental

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 adverse effect on the financial position or results of operations of the Company.

Litigation

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 litigation and claims currently pending will not have a material adverse effect on the financial position or results of operations of the Company.

(9)

STOCK-BASED COMPENSATION

The Company has incentive plans that provide for the issuance of equity awards, including stock options and restricted stock. These plans are discussed more fully in Note 9 of the Notes to Consolidated Financial Statements included in Item 8 of the 2006 Annual Report on Form 10-K. The Company has issued options and restricted stock under these plans. All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under the 2004 Plan and ten years from the date of grant for awards under all other plans. Generally, stock options granted to employees and directors vest ratably over three to four years from the grant date. There were no stock options granted during the first nine months of 2007. The Company issues shares of restricted stock to employees and directors which generally vest over four years. The Company

recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age and have met the minimum service requirements in order to become fully vested prior to the requisite service period.

For the third quarter and first nine months of 2007, the Company recorded compensation cost of $0.6 and $1.9 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.2 million and $0.5 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool. The Company also recorded a deferred tax benefit of $0.7 million related to stock options for the nine months ended September 30, 2007. A total of $3.9 million of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods. For the third quarter and first nine months of 2006, the Company recorded compensation cost of $1.4 and $2.5 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.1 million and $0.4 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool.

For the third quarter and first nine months of 2007, the Company recorded compensation cost of $0.6 and $1.9 million, respectively, in general and administrative expense related to prior restricted stock grants. Additional amounts of $0.5 million and $1.4 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool. As of September 30, 2007, there was $9.6 million of total unrecognized compensation cost related to nonvested shares of restricted stock. For the third quarter and first nine months of 2006, the Company recorded compensation cost of $0.6 and $1.5 million, respectively, in general and administrative expense related to restricted stock. Additional amounts of $0.3 million and $0.9 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool.

The following tables summarize stock option activity for the first three quarters of 2007 and provide information for options outstanding at September 30, 2007:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2006	5,792,240	$ 6.19
Granted	-	-
Exercised	(1,338,931)	3.11
Forfeited or expired	(12,000)	20.91
Outstanding at September 30, 2007	4,441,309	$ 7.09
Exercisable at September 30, 2007	3,893,005	$ 3.96

During the first nine months of 2007 and 2006 there were no options granted. The total intrinsic value of options exercised during the first nine months of 2007 and 2006 was $52.1 million and $25.6 million, respectively. Associated with the exercise of stock options, the Company received a tax benefit of $17.9 million and $7.4 million in the first nine months of 2007 and 2006, respectively. The tax benefit is recorded as an increase in additional paid-in capital.

	Options Outstanding				Options Exercisable		
Range of Exercise Prices	Options Outstanding at September 30, 2007	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at September 30, 2007	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)

$1.50 - $1.86	1,683,243	$	1.75	2.8		1,683,243	$ 1.75	
$1.87 - $2.85	461,307		2.52	3.8		461,307	2.52	
$2.86 - $5.00	751,806		2.91	4.9		751,806	2.91	
$5.01 - $12.00	733,514		5.49	6.2		693,514	5.45	
$12.01 - $42.00	811,439		26.06	5.0		303,135	17.63	
	4,441,309	$	7.09	4.2	$ 154,401	3,893,005	$ 3.96	$ 147,501

The following table summarizes restricted stock activity for the first nine months of 2007:

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2006	478,732	$ 25.30
Granted	35,550	39.07
Vested	(16,633)	17.79
Forfeited	(21,842)	29.99
Unvested shares at September 30, 2007	475,807	$ 26.37

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PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." 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, 2007 and 2006:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006
	(in thousands)			

Service cost	$ 995	$ 753	$ 2,987	$ 2,258
Interest cost	1,061	971	3,182	2,911
Expected return on plan assets	(1,140)	(1,145)	(3,419)	(3,433)
Amortization of prior service cost	119	109	356	327
Amortization of net loss	115	189	345	569
Net periodic benefit cost	$ 1,150	$ 877	$ 3,451	$ 2,632

	Postretirement Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006
	(in thousands)			
Service cost	$ 104	$ 68	$ 313	$ 203
Interest cost	54	47	162	141
Expected return on plan assets	(21)	(18)	(61)	(52)
Amortization of net loss	6	9	16	26
Amortization of transition obligation	22	22	65	65
Net periodic benefit cost	$ 165	$ 128	$ 495	$ 383

The Company currently expects to contribute \$6.5 million to the pension plans and \$0.4 million to the postretirement benefit plans in 2007. As of September 30, 2007, \$4.5 million has been contributed to our pension plans, and \$0.3 million has been contributed to the postretirement benefit plans.

The Company also maintains a non-qualified defined contribution supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation, as permitted by the plan. The Company maintains supplemental retirement savings plan assets that are accounted for in accordance with EITF Issue No. 97-14, Accounting for Deferred Compensation Arrangements Where Accounts are Held in a Rabbi Trust and Invested (EITF 97-14), and the underlying assets are held in a Rabbi Trust. Shares of the Company s common stock purchased under a non-qualified deferred compensation arrangement are held in a Rabbi Trust and are presented as treasury stock. As of September 30, 2007, 111,162 shares were accounted for as treasury stock.

(11)

ASSET RETIREMENT OBLIGATIONS

Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," (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 (in thousands) for the nine-month period ended September 30, 2007 and for the year ended December 31, 2006:

Asset retirement obligation at January 1	$ 10,545	$ 9,229
Accretion of discount	346	401
Obligations incurred	1,683	1,152
Obligations settled/removed	(329)	(645)
Revisions of estimates	-	408
Asset retirement obligation at September 30, 2007 and December 31, 2006	$ 12,245	$ 10,545
Current liability	727	593
Long-term liability	11,518	9,952
Asset retirement obligation at September 30, 2007 and December 31, 2006	$ 12,245	$ 10,545

(12)

NEW ACCOUNTING PRONOUNCEMENTS

During the first quarter of fiscal 2007, the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a threshold condition that a tax position must meet to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 had no material impact on the Company s results of operations and financial condition. The income tax years 2003-2006 remain open to examination by the major taxing jurisdictions to which the Company is subject.

In September 2006, the Financial Accounting Standards Board issued SFAS No. 157, Fair Value Measurements (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Prior to this statement, there were different definitions of fair value and limited guidance for applying those definitions in GAAP. In developing FAS 157, FASB considered the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. This statement applies to other accounting pronouncements that require or permit fair value measurements. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company has not yet determined the impact FAS 157 may have on its results of operations or financial condition.

In February 2007, the Financial Accounting Standards Board issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (FAS 159). FAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value. Most of the provisions of this statement apply only to entities that elect the fair value option. This statement applies to other accounting pronouncements that require or permit fair value measurements. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company has not yet determined the impact FAS 159 may have on its results of operations or financial condition.

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 2006 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, 2007 and 2006. 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 2006 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 our forward-looking statements for many reasons, including the risks described in the Forward-Looking Information in the fore part of this Form 10-Q, in Item 1A, "Risk Factors" in Part I and elsewhere in our 2006 Annual Report on Form 10-K, and Item 1A, Risk Factors in Part II in this Form 10-Q. You should read the following discussion with our financial statements and related notes included in this Form10-Q.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil within the United States, with operations principally located in Arkansas, Oklahoma, Texas and New Mexico. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution and marketing businesses and our expanding gathering activities. Our marketing and our gas gathering businesses are collectively referred to as our Midstream Services. We operate principally in three segments: Exploration and Production (E&P), Midstream Services and Natural Gas Distribution.

Our business strategy is focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. In our E&P business, we prepare economic analyses for each of our drilling and acquisition opportunities and rank them based upon the expected present value added for each dollar invested, which we refer to as PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. Our actual PVI results are utilized to help determine the allocation of our future capital investments.

We 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. In recent years, there has been significant price volatility in natural gas and crude oil prices 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, which determines the pricing. 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.

Three Months Ended September 30, 2007, Compared with Three Months Ended September 30, 2006

In the third quarter of 2007, our gas and oil production increased to 30.0 Bcfe, up 56% from the third quarter of 2006. The increase in 2007 production primarily resulted from a significant increase in production from our Fayetteville Shale play as a result of our ongoing development program.

We reported net income of $51.0 million in the third quarter of 2007, or $0.30 per share on a fully diluted basis, up 52% from the prior year, due to increased production volumes in our E&P segment and higher realized natural gas prices, which were up 7% from the third quarter of 2006, partially offset by increased operating costs and expenses. Operating income for our E&P segment was $88.9 million for the third quarter of 2007, up 58% from the comparable period of 2006 as a result of the increased production volumes and higher realized prices for our gas production, partially offset by increased operating costs and expenses. Operating income for our Midstream Services segment was $4.1 million for the third quarter of 2007, up from $1.3 million in the third quarter of 2006, due primarily to an increase in gathering revenues related to our Fayetteville Shale play. Our Natural Gas Distribution segment s seasonal loss decreased 22% to $3.5 million for the three months ended September 30, 2007, primarily due to the implementation of a rate increase and decreased operating costs and expenses.

Our capital investments increased approximately 61% to $416.6 million for the third quarter of 2007, of which $381.1 million was invested in our E&P segment.

Nine Months Ended September 30, 2007, Compared with Nine Months Ended September 30, 2006

For the nine months ended September 30, 2007, our gas and oil production increased to 78.7 Bcfe, up 53% compared to the same period in 2006. The increase in 2007 production primarily resulted from the increase in production from our Fayetteville Shale play.

We reported net income of $149.5 million for the first nine months of 2007, or $0.87 per share on a fully diluted basis, up 16% from the prior year, due primarily to increased production volumes in our E&P segment, partially offset by increased operating costs and expenses. Our cash flow from operating activities was $435.0 million for the first nine months of 2007, up from $331.1 million, due primarily to an increase in net income and adjustments to net income for non-cash expenses. Operating income for our E&P segment was $244.5 million for the nine months ended September 30, 2007, up from $186.6 million in the comparable period of 2006, as a result of the increased production volumes, partially offset by increased operating costs and expenses. Operating income for our

Midstream Services segment was $6.4 million for the first nine months of 2007, up from $3.1 million for the same period of 2006, due to an increase in gas gathering revenues related to the Fayetteville Shale play. Operating income for our Natural Gas Distribution segment increased to $4.1 million for the nine months ended September 30, 2007, up from $1.3 million in the comparable period of 2006, primarily due to colder weather in the first part of the year and the implementation of a rate increase effective August 2007.

Our capital investments increased approximately 80% to $1,140.7 million for the nine months ended September 30, 2007, of which $1,051.4 million was invested in our E&P segment.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006
Revenues (in thousands)	$204,130	$124,772	$547,189	$360,245
Operating income (in thousands)	$88,856	$56,326	$244,518	$186,606
Gas production (MMcf)	29,145	18,175	75,879	48,415
Oil production (MBbls)	139	180	472	527

Total production (MMcfe)	29,982	19,255	78,714	51,577
Average gas price per Mcf, including hedges	$6.66	$6.23	$6.75	$6.73
Average gas price per Mcf, excluding hedges	$5.49	$6.04	$6.13	$6.56
Average oil price per Bbl, including hedges	$72.52	$62.78	$62.58	$60.24
Average oil price per Bbl, excluding hedges	$72.52	$68.31	$62.58	$65.31
Average unit costs per Mcfe				
Lease operating expenses	$0.67	$0.68	$0.71	$0.62
General & administrative expenses	$0.46	$0.54	$0.47	$0.56
Taxes, other than income taxes	$0.11	$0.32	$0.19	$0.34
Full cost pool amortization	$2.56	$1.97	$2.41	$1.79

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up 64% for the three months ended September 30, 2007, compared to the same period in 2006, primarily due to increased production volumes and higher gas prices realized for our production. Revenues were up 52% for the nine months ended September 30, 2007, compared to the first nine months of 2006, primarily due to increased production volumes. Revenues for the first nine months of 2007 and 2006 also included pre-tax gains of $5.1 million and $1.9 million, respectively, related to the sale of gas in storage inventory. We expect our production volumes to continue to increase due to the continued development of our Fayetteville Shale play in Arkansas. Gas and oil prices are difficult to predict and subject to wide price fluctuations. As of November 5, 2007, we have hedged 22.0 Bcf of our remaining 2007 gas production, 97.0 Bcf of 2008 gas production and 72.0 Bcf of 2009 gas production to limit our exposure to price fluctuations.

Operating Income. Operating income for the E&P segment was up 58% to $88.9 million for the third quarter of 2007 from $56.3 million for the same period in 2006. For the nine months ended September 30, 2007, operating income increased 31% to $244.5 from $186.6 for the same period in 2006. The increases in operating income were a result of the increases in revenues, partially offset by increases in operating costs and expenses.

Production. Gas and oil production during the third quarter of 2007 was up approximately 56% to 30.0 Bcfe and was up approximately 53% to 78.7 Bcfe for the first nine months of 2007, as compared to prior periods, due to an increase in production from our Fayetteville Shale play as a result of our ongoing development program. Our total gas production was up approximately 60% to 29.1 Bcf for the third quarter of 2007, which represented approximately 97% of our total equivalent production, and up approximately 57% to 75.9 Bcf for the first nine months of 2007. Net production from the Fayetteville Shale was 14.7 Bcf in the third quarter of 2007, compared to 3.8 Bcf in the third quarter of 2006. For the first nine months of 2007, production from the Fayetteville Shale was 33.6 Bcf compared to

6.3 Bcf for the first nine months of 2006.

Commodity Prices

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 3 and Note 5 of the Notes to Consolidating Financial Statements in this Form 10-Q for additional discussion). The average price realized for our gas production, including the effect of hedges, increased approximately 7% to $6.66 per Mcf for the three months ended September 30, 2007, and increased slightly to $6.75 for the first nine months of 2007, as compared to the same periods last year. The change in the average price realized primarily reflects changes in average spot market prices and the positive effects of our price hedging activities. Our hedging activities increased our average gas price $1.17 and $0.19 per Mcf during the third quarters of 2007 and 2006, respectively. Our hedging activities increased our average gas price $0.62 per Mcf for the first nine months of 2007, compared to an increase of $0.17 per Mcf during the same period of 2006. Locational differences in market prices for natural gas have continued to be wider than historically experienced. We had financially protected approximately 75% of our production in the third quarter of 2007 from the impact of widening basis differentials. For the fourth quarter of 2007, we have protected approximately 83% of our anticipated gas production from the impact of widening basis differentials through our hedging activities and sales arrangements. Disregarding the impact of hedges, the average price received for our gas production during the first nine months of 2007 was approximately $0.70 lower than average NYMEX spot prices, which represented the average locational basis differential.

As of November 5, 2007, we have NYMEX commodity price hedges in place for 22.0 Bcf of our remaining 2007 gas production. For our 2008 and 2009 future gas production, we have hedges in place on 97.0 Bcf and 72.0 Bcf, respectively. Additionally, we have basis swaps on 18.0 Bcf for the remainder of 2007, and for 2008 and 2009, we have basis swaps on 61.7 Bcf and 1.8 Bcf, respectively, in order to reduce the effects of changes in market differentials on prices we receive.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were down slightly to $0.67 for the third quarter of 2007, and increased 15% to $0.71 for the first nine months of 2007, both as compared to the same periods in 2006. The decrease in lease operating expenses per Mcfe for the third quarter resulted primarily from a decline in the cost of fuel gas for our compression-related expenses, partially offset by increases in gathering costs, both primarily related to our Fayetteville Shale play. The increase in the year-to-date cost was primarily a result of increases in our gathering and compression costs related to our operations in the Fayetteville Shale play. Based on our projected production, we expect our per unit operating costs for 2007 to be approximately $0.75 per Mcfe.

General and administrative expenses per Mcfe decreased 15% to $0.46 for the third quarter of 2007 and 16% to $0.47 for the first nine months of 2007, due primarily to the effects of our increased production volumes. Total general and administrative expenses for our E&P segment were $13.7 million in the third quarter of 2007, compared to $10.4 million in the third quarter of 2006 and were $36.8 million for the first nine months of 2007, compared to $28.7 million for the first nine months of 2006. The increases in general and administrative costs were due primarily to increased payroll and related costs associated with the expansion of our E&P operations due to the Fayetteville Shale play. We expect our per unit G&A expense to continue to decline for the remainder of 2007 and to be approximately $0.47 per Mcfe for the year due to increased production volumes from our Fayetteville Shale play.

Our full cost pool amortization rate averaged $2.56 per Mcfe for the third quarter of 2007 and $2.41 for the first nine months of 2007, up 30% and 35%, respectively, compared to the same periods in 2006. Our full cost pool amortization rate increased due to increased capital investments and future development costs relative to reserve additions, including revisions. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, and the level of unevaluated costs excluded from amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as the uncertainty of the amount of future reserves attributed to our Fayetteville Shale play. Unevaluated costs excluded from amortization were $288.8 million at September 30, 2007, compared to $169.7 million at September 30, 2006. The increase in unevaluated costs since September 30, 2006 resulted primarily from an increase in our undeveloped leasehold acreage and seismic costs related to our Fayetteville Shale play and our increased drilling activity.

Taxes other than income taxes per Mcfe decreased to $0.11 for the third quarter of 2007, compared to the same period in 2006 and decreased to $0.19 for the nine months ended September 30, 2007, compared to the first nine months of 2006, primarily due to the changing mix of production. Additionally, we accrued $2.0 million in the third quarter and $3.3 million for the first nine months of 2007 for severance tax refunds related to our East Texas production.

The timing and amount of production and reserve additions attributed to our Fayetteville Shale play could have a material impact on per unit costs; if production or reserves additions are lower than projected, our per unit costs would increase.

We utilize the full cost method of accounting for costs related to the exploration, development, and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural 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 the 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. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At September 30, 2007, the ceiling value of our reserves was calculated based upon quoted market prices of $6.38 per Mcf for Henry Hub gas and $78.25 per barrel for West Texas Intermediate oil, adjusted for market differentials. At September 30, 2007, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. Cash flow hedges of gas production in place at September 30, 2007 increased the calculated ceiling value by approximately $225.0 million (net of tax). Without the effects of cash flow hedges, our unamortized costs of natural gas and oil properties would have exceeded the ceiling amount. We had approximately 174.0 Bcf of future gas production hedged at September 30, 2007. Decreases in market prices from September 30, 2007 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

Midstream Services

	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006
	($ in thousands)			
Revenues - marketing	$228,771	$122,519	$628,609	$332,760
Revenues - gathering	$10,256	$2,808	$22,674	$4,701
Gas purchases - marketing	$226,209	$120,571	$622,109	$325,957
Operating costs and expenses	$8,740	$3,497	$22,775	$8,376
Operating income	$4,078	$1,259	$6,399	$3,128
Gas volumes marketed (Bcf)	40.2	20.1	99.5	50.5

Revenues from our Midstream Services segment were up 91% in the third quarter of 2007 and up 93% for the first nine months of 2007, as compared to prior year periods. The increases in revenues primarily resulted from an increase in volumes marketed and increased gathering revenues. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expense. Midstream Services had gathering revenues of $10.3 million in the third quarter of 2007 and $22.7 million for the first nine months of 2007, compared to $2.8 million and $4.7 million for the comparable periods of 2006. Gathering revenues and expenses for this segment are expected to continue to grow in the future as reserves related to our Fayetteville Shale play are developed and production increases. Operating income from our Midstream Services

segment increased 224% in the third quarter of 2007 and 105% for the first nine months of 2007, as compared to the same periods of 2006 as a result of the increases in marketing and gathering revenues from the Fayetteville Shale play, partially offset by increased operating costs and expenses. The margin generated from natural gas marketing activities was up 32% for the third quarter of 2007 and down 4% for the first nine months of 2007 as compared to the same periods of 2006. Margins fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increase in volumes marketed in the third quarter of 2007, as compared to the same period in 2006, resulted from increased production volumes in the Fayetteville Shale play. For the third quarter of 2007, 70% of our volumes marketed related to affiliated gas production volumes, compared to 74% for the same period in 2006. For the first nine months of 2007, 71% of volumes marketed related to affiliated gas production volumes, compared to 72% for the same period in 2006. 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, "Quantitative and Qualitative Disclosures about Market Risks" in this Form 10-Q for additional information.

Natural Gas Distribution

	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006
Revenues (in thousands)	$17,254	$18,295	$121,853	$119,140
Gas purchases (in thousands)	$7,557	$9,128	$77,960	$77,257
Operating costs and expenses (in thousands)	$13,238	$13,697	$39,759	$40,598
Operating income (loss) (in thousands)	($3,541)	($4,530)	$4,134	$1,285
Sales and end-use transportation deliveries (Bcf)	3.0	3.0	16.7	14.9
Sales customers at period-end	148,111	145,987	148,111	145,987
Average sales rate per Mcf	$13.22	$14.21	$11.11	$13.11
Heating weather - degree days	9	55	2,309	2,005
Percent of normal	23%	117%	92%	79%

Revenues and Operating Income

Revenues decreased 6% for the third quarter of 2007 and increased 2% for the nine months ended September 30, 2007, compared to the comparable periods of 2006. The decrease in third quarter revenues resulted primarily from a decrease in the average sales rate per Mcf. The increase in revenues for the first nine months of 2007 was due to an increase in volumes delivered, offset by a decrease in the average sales rates per Mcf. Weather during the first nine months of 2007 was 8% warmer than normal and 13% colder than the same period in 2006.

The seasonal operating loss in the third quarter of 2007 decreased 22% and operating income for the nine months ended September 30, 2007 increased 222%, both as compared to the comparable

periods of 2006. The decrease in the third quarter 2007 operating loss resulted from decreased operating costs and expenses and a rate increase implemented in August 2007. The increase in operating income for the first nine months of 2007 resulted from an increase in volumes delivered, decreased operating costs and expenses and the rate increase implemented in August 2007.

Deliveries and Rates

Deliveries were even in the third quarter and increased 12% in the nine-months ended September 30, 2007, as compared to the same periods in 2006. The increase in deliveries for the first nine months of 2007 was due to the colder weather. The average sales rate per Mcf decreased during the third quarter and the first nine months due to changes in natural gas prices and the impact of incremental volumes delivered.

Our utility segment hedged 3.1 Bcf of derivative gas purchases during the first nine months of 2007, which had the effect of increasing its total gas supply cost by $6.6 million. In the first nine months of 2006, our utility hedged 1.8 Bcf of its gas supply, which increased its total gas supply cost by $6.8 million. Additionally, our utility segment currently has hedges in place on 2.9 Bcf of gas purchases at an average purchase price of $8.42 per Mcf for the 2007-2008 winter season. See Note 5 of the Notes to Consolidated Financial Statements and Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

In July 2007, the APSC approved a rate increase for our utility segment totaling $5.8 million annually, exclusive of costs to be recovered through the utility s purchase gas adjustment clause. The rate increase became effective for billings rendered on or after August 1, 2007. The APSC order provided for an allowed return on equity of 9.5% and an assumed capital structure of 55% debt and 45% equity.

Operating Costs and Expenses

For the first nine months of 2007, operating costs and expenses (exclusive of purchased gas costs) for this segment were lower than the comparable period of the prior year due primarily to lower general and administrative expenses. The decrease in general and administrative expenses primarily resulted from a decrease in corporate expenses allocated to the Natural Gas Distribution segment.

Transportation

In the second quarter of 2006, we sold our 25% partnership interest in NOARK to Atlas Pipeline Partners, L.P. for $69.0 million and recognized a pre-tax gain of approximately $10.9 million ($6.7 million after tax) relating to the transaction. Pre-tax income from operations of $0.9 million for the first six months of 2006 and the gain on the sale in the second quarter were recorded in other income in our statements of operations.

Other Revenues

Other revenues for the first nine months of 2007 and 2006 included pre-tax gains of $5.1 million and $1.9 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, increased to $7.3 million and $13.7 million for the third quarter and the first nine months of 2007, respectively, due to increased debt levels resulting from our increased level of capital investments. We capitalized $9.6 million of interest in the first nine months of 2007, compared to $8.2 million for the same period in 2006, as our costs excluded from amortization in the E&P segment increased to $288.8 million at September 30, 2007, compared to $169.7 million at September 30, 2006. Additionally in 2006, interest was capitalized during the construction period of drilling rigs that were ultimately sold and leased back in December 2006.

During the first nine months of 2006, we earned interest income of $6.2 million related to our investment in cash equivalents. This amount was recorded in other income. We had no cash investments as of September 30, 2007.

Income Taxes

Our provision for deferred income taxes was an effective rate of 38.0% for both the first nine months of 2007 and 2006. Any 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 incurred pension costs of $1.3 million and $3.9 million in the third quarter and first nine months of 2007, respectively, for our pension and other postretirement benefit plans, compared to $1.0 million and $3.0 million for the same periods of 2006. The increases were primarily the result of an increase in our number of employees. The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $6.9 million to our pension and other postretirement plans in 2007. As of September 30, 2007, $4.5 million has been contributed to our pension plans and $0.3 million has been contributed to our other postretirement plans. For further information regarding our pension plans, we refer you to Note 10 of the Notes to Consolidated Financial Statements in this Form 10-Q.

Stock-Based Compensation

We recognized expense of $3.8 million and capitalized $1.9 million to the full cost pool for stock-based compensation in the first nine months of 2007, compared to $4.0 million expensed and $1.3 million capitalized to the full cost pool for the comparable period of 2006. We refer you to Note 9 of the Notes to Consolidated Financial Statements in this Form 10-Q for additional discussion of our equity based compensation plans.

Adoption of Accounting Principles

During the first quarter of 2007, we adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in FAS 109. FIN 48 prescribes a threshold condition that a tax position must meet to be recognized in the financial statements. Guidance is also provided regarding

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de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 had no material impact on our results of operations and financial condition.

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 may borrow up to $1.0 billion under our revolving credit facility from time to time. The amount available under our revolving credit facility may be increased up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of September 30, 2007, we had $594.3 million outstanding under our revolving credit facility. At December 31, 2006, we had no indebtedness outstanding under our revolving credit facility.

Net cash provided by operating activities increased 31% to $435.0 million in the first nine months of 2007, compared to the same period in 2006, due primarily to an increase in net income and adjustments for non-cash expenses. For the first nine months of 2007, requirements for our capital investments were met primarily by our revolving credit facility, cash provided by operating activities, and cash equivalents from the sale and leaseback of our drilling rigs on December 29, 2006.

At September 30, 2007, our capital structure consisted of 31% debt and 69% equity. We believe that our operating cash flow and the amount available for borrowing under our credit facility will be adequate to meet our capital and operating requirements for the remainder of 2007. If the level of cash flow generated by our operations is insufficient and/or our credit facility is unavailable, we may access the public debt and/or equity markets or adjust our level of 2007 capital investments. We expect to raise funds in the public debt and/or equity markets in order to meet a significant portion of our future cash requirements.

Our cash flow from operating activities is highly dependent upon market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Item 3, "Quantitative and Qualitative Disclosures about Market Risks" and Note 5 to the Notes to Consolidating Financial Statements in this Form 10-Q. 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 Investments

Our capital investments increased 80% to $1,140.7 million for the first nine months of 2007 as compared to $632.1 million for the same period last year. Our E&P segment investments during the first nine months of 2007 were $1,051.4 million and were $577.9 million for the comparable period in 2006, including $73.8 million for drilling rigs that were subsequently sold and leased back in December 2006. We are currently projecting capital investments for 2007 of $1,455 million, including approximately $1,335 million related to our E&P segment, of which we expect to allocate approximately $940 million to our Fayetteville Shale play. Our capital investment program for the remainder of 2007 is expected to be funded through cash flow from operations and borrowings under our revolving credit facility. If the level of cash flow generated by our operations is insufficient and/or our credit facility is unavailable, we may access the public debt and/or equity markets or adjust our level of 2007 capital investments. We expect to raise funds in the public debt and/or equity markets in order to meet a significant portion of our future capital investment programs.

Financing Requirements

Our total debt outstanding was $731.5 million at September 30, 2007, compared to $137.8 million at December 31, 2006. On October 12, 2007, we amended our unsecured revolving credit facility to, among other things, increase the current borrowing capacity to $1.0 billion. Pursuant to the amendment, the amount available under the revolving credit facility may be increased to $1.25 billion at any time upon the Company s agreement with its existing or additional lenders. At September 30, 2007, we had $594.3 million debt under our revolving credit facility. The interest rate on the facility is calculated based upon our public debt rating and is currently 87.5 basis points over LIBOR. The revolving credit facility is currently guaranteed by our subsidiaries, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. Our publicly traded notes were downgraded on August 1, 2006 by Standard and Poor s to BB+ with a stable outlook from BBB- with a negative outlook. We have a Corporate Family Rating of Ba2 by Moody s, and our publicly traded notes were rated Ba3 by Moody s under Moody s Loss Given Default Assessment on September 19, 2006. Any future downgrades in our public debt ratings could increase our cost of funds under the credit facility. We do not expect our current ratings to impact our ability to obtain acceptable financing terms if we elect to access the public debt market.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreement, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of stockholders equity and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Additionally, there are certain limitations on the amount of indebtedness that may be incurred by our subsidiaries. We were in compliance with all of the covenants of our credit agreement at September 30, 2007. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants 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 investment plans.

At September 30, 2007, our capital structure consisted of 31% debt and 69% equity. Stockholders equity in the September 30, 2007 balance sheet includes an accumulated other comprehensive gain of $44.2 million related to our hedging activities that is required to be recorded under the provisions of Statement on Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133), and a loss of $9.5 million related to changes in our pension liability and the adoption of Statement on Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (FAS 158). The amount recorded for FAS 133 is based on current market values of our hedges at September 30, 2007, 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 credit facility s financial covenants with respect to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 and FAS

158 and the non-cash impact of any full cost ceiling write-downs. Our capital structure at September 30, 2007 would have

been 32% debt and 68% equity without consideration of the accumulated other comprehensive gain and loss related to FAS 133 and FAS 158.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 75% of our expected 2007 gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans. If commodity prices remain at or near their current levels throughout the remainder of 2007, our capital investment plans do not change and we do not issue equity, we will increase our long-term debt in 2007 by approximately $775 to $825 million. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital investments.

Off-Balance Sheet Arrangements

On May 2, 2006, we sold our 25% partnership interest in NOARK to Atlas Pipeline Partners, L.P., for $69.0 million. As part of the transaction, we assumed and recorded $39.0 million of debt obligations of NOARK Pipeline Finance, L.L.C., which we had previously guaranteed as part of the financing of NOARK.

On December 29, 2006, we entered into a sale and leaseback transaction pursuant to which we sold 13 operating drilling rigs, two rigs yet to be delivered and related equipment and then leased such drilling rigs and equipment for an initial term of eight years commencing January 1, 2007, with aggregate annual rental payments of approximately $19.6 million. Subject to certain conditions, we have options to purchase the rigs and related equipment from the lessors at the end of the 84th month of the lease term at an agreed upon price, or at the end of the lease term for the then fair market value. Additionally, we have the option to renew each lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations other than as disclosed in our 2006 Annual Report on Form 10-K and our Form 10-Q for the period ended June 30, 2007.

Contingent Liabilities and 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 expenses of $5.3 million in 2007 for these plans, of which $3.9 million has been recorded in the first nine months of 2007. At September 30, 2007, we had an accrued pension benefit liability recorded of $9.9 million. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 10 of the Notes to Consolidated Financial Statements in this Form 10-Q.

We are subject to litigation and claims (including with respect to environmental matters) 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.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had negative working capital of $118.4 million at September 30, 2007, and $55.0 million at December 31, 2006. Current assets decreased at September 30, 2007 primarily due to a decrease of $42.0 million in cash equivalents. Current liabilities increased $50.6 million primarily due to an increase in our accounts payable at September 30, 2007. Both changes reflect our increased level of capital investments as discussed in Capital Investments above.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 10.5 Bcf at $4.13 per Mcf at September 30, 2007, and 9.6 Bcf at $3.89 per Mcf at December 31, 2006.

The gas in inventory for the E&P segment is used to supplement field production in meeting the segment's contractual commitments, including delivery to customers of our natural gas distribution business, particularly during periods of colder weather. 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.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

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

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of customers and their dispersion across geographic areas. No single customer accounts for greater than 4% of accounts receivable at September 30, 2007. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At September 30, 2007, we had $731.5 million of total debt with an average interest rate of 6.34%. Our revolving credit facility has a floating interest rate (6.10% at September 30, 2007). At September 30, 2007, we had $594.3 million of borrowings outstanding under the facility. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate. We 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 midstream services segment, and to hedge the purchase of gas in our natural gas distribution segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the 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 that 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 limit our credit risk exposure.

Exploration and Production

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 future gas production. The table presents the notional amount in Bcf (billion cubic feet), the weighted average contract prices, and the fair value by expected maturity dates. At September 30, 2007, the fair value of our financial instruments related to natural gas production and underground storage sales was a $74.8 million asset.

	Volume	Weighted Average Price to be Swapped ($)	Weighted Average Floor Price ($)	Weighted Average Ceiling Price ($)	Weighted Average Basis Differential ($)	Fair Value at September 30, 2007 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2007 (1)	12.1	8.11	-	-	-	13.0
2008 (2)	41.7	8.32	-	-	-	19.7
2009	42.0	8.15	-	-	-	1.2

Costless Collars:						
2007	10.5	-	7.10	11.21	-	6.2
2008	48.0	-	7.92	11.60	-	25.5
2009	22.0	-	8.07	10.94	-	4.9
Basis Swaps:						
2007	9.5	-	-	-	(0.66)	(0.6)
2008	52.5	-	-	-	(0.53)	2.9
Matched-Basis Swaps:						
2007	8.5	-	-	-	(0.46)	1.8
2008	8.0	-	-	-	(0.73)	0.2

(1)

Includes fixed-price swaps for 0.6 Bcf relating to future sales from our underground storage facility that have a fair value asset of $0.5 million.

(2)

Includes fixed-price swaps for 1.7 Bcf relating to future sales from our underground storage facility that have a fair value asset of $1.1 million.

At September 30, 2007, we had outstanding fixed-price basis differential swaps on 9.5 Bcf of 2007 and 52.5 Bcf of 2008 gas production that did not qualify for hedge accounting treatment, as shown in the table above. The fair value of these differential swaps was an asset of $2.3 million at September 30, 2007. As of November 5, 2007, we have basis-protected an additional 3.0 Bcf of future gas production subsequent to the end of the quarter.

At December 31, 2006, the Company had outstanding natural gas price swaps on total notional volumes of 32.5 Bcf in 2007 and 13.0 Bcf in 2008 for which the Company will receive fixed prices ranging from $6.20 to $12.06 per MMBtu. At December 31, 2006, the Company had outstanding fixed price basis differential swaps on 62.0 Bcf of 2007 and 2008 gas production that did not qualify for hedge treatment.

At December 31, 2006, the Company had collars in place on notional volumes of 34.0 Bcf in 2007 and 22.0 Bcf in 2008. The 34.0 Bcf in 2007 had an average floor and ceiling price of $6.93 and $12.34 per MMBtu, respectively. The 22.0 Bcf in 2008 had an average floor and ceiling price of $7.92 and $13.15 per MMBtu, respectively.

Midstream Services

At September 30, 2007, our Midstream Services segment had outstanding hedges in place on 1.1 Bcf of gas. These hedges are a mixture of fixed-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from October 2007 through December 2008 and have fair value asset of $0.8 million as of September 30, 2007. An additional liability of $0.7 million was recognized as an offset to these hedges for physical gas purchases and sales commitments relating specifically to the hedged deals.

Natural Gas Distribution

At September 30, 2007, our Natural Gas Distribution segment had outstanding hedges in place on 2.9 Bcf of gas. These hedges are fixed-price swap purchases that relate to the utility s planned and discretionary hedging program for the winter heating season that have a weighted average price of $8.42. These hedges have contract months from November 2007 through March 2008, and have a fair value liability of $1.6 million as of September 30, 2007.

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, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission 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, 2007, and provided a level of reasonable assurance with respect to financial statement preparation and presentation. There were no changes in our internal control over financial reporting during the three months ended September 30, 2007 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. 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.

ITEM 1A. RISK FACTORS.

There were no additions or material changes to the Company s risk factors as disclosed in Item 1A of Part I in the Company s 2006 Annual Report on Form 10-K.

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.

(4.1)

First Amendment to Second Amended and Restated Credit Agreement dated October 12, 2007 by and among Southwestern Energy Company, JPMorgan Chase Bank, NA, SunTrust Bank, The Royal Bank of Scotland PLC, Royal Bank of Canada, Bank of America, N.A., and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent, SunTrust Bank as syndication agent.

(31.1)

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

(31.2)

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

(32.1)

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

Signatures

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

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: November 7, 2007

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