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 **June 30, 2008**

or

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

Commission file number: **1-08246**

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 North Sam Houston Pkwy. East, 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 12 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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer _X_ Accelerated filer ___ Non-accelerated filer ___ Smaller reporting company ___

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 as of July 25, 2008
Common Stock, Par Value $0.01	343,184,434

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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, except as may be required by law.

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;
- our ability to fund our planned capital investments;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- the impact of federal, state and local government regulation, including any increase in severance taxes;
- the costs and availability of oilfield 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 financial impact of accounting regulations and critical accounting policies;
- 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 contained in this Form 10-Q 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, 2007 (the "2007 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 this Form 10-Q occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

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

PART I

FINANCIAL INFORMATION

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended June 30, 2008	For the three months ended June 30, 2007	For the six months ended June 30, 2008	For the six months ended June 30, 2007
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 368,879	$ 184,059	$ 729,550	$ 395,703
Gas marketing	208,071	72,238	345,298	127,555
Oil sales	15,538	10,216	29,251	19,453
Gas gathering, transportation and other	11,882	3,569	24,377	12,023
	604,370	270,082	1,128,476	554,734
Operating Costs and Expenses:				
Gas purchases - midstream services	202,889	69,488	335,341	122,705
Gas purchases - gas distribution	9,544	7,427	61,439	55,408
Operating expenses	30,030	20,485	54,026	40,522
General and administrative expenses	25,741	17,935	49,481	34,683
Depreciation, depletion and amortization	98,151	66,435	195,248	122,220
Taxes, other than income taxes	8,729	6,306	16,145	13,431
	375,084	188,076	711,680	388,969
Operating Income	229,286	82,006	416,796	165,765
Interest Expense:				
Interest on long-term debt	15,659	7,384	32,745	11,509
Other interest charges	619	545	1,267	926
Interest capitalized	(7,281)	(2,923)	(13,486)	(5,971)
	8,997	5,006	20,526	6,464
Other Income (Loss)	169	(125)	176	(104)
Income Before Income Taxes and Minority Interest	220,458	76,875	396,446	159,197
Minority Interest in Partnership	(215)	(111)	(350)	(194)
Income Before Income Taxes	220,243	76,764	396,096	159,003
Provision for Income Taxes				
Current	46,500	-	46,500	-
Deferred	37,193	29,170	104,017	60,421
	83,693	29,170	150,517	60,421
Net Income	$ 136,550	$ 47,594	$ 245,579	$ 98,582
Earnings Per Share:				
Basic	$ 0.40	$ 0.14 (1)	$ 0.72	$ 0.29 (1)
Diluted	$ 0.39	$ 0.14 (1)	$ 0.71	$ 0.29 (1)
Weighted Average Common Shares Outstanding:				
Basic	341,402,888	338,933,824 (1)	341,233,574	338,073,050 (1)
Diluted	346,551,198	345,001,082 (1)	346,287,843	344,537,804 (1)

(1) Restated to reflect the two-for-one stock split effected on March 25, 2008.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

ASSETS

	June 30, 2008	December 31, 2007
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 177,091	$ 727
Accounts receivable	306,794	177,680
Inventories, at average cost	27,814	33,034
Hedging asset - FAS 133	52,048	64,472
Deferred income tax benefit	173,807	-
Current assets held for sale (see Note 4)	42,926	58,877
Other	25,513	28,551
Total current assets	805,993	363,341
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $415.9 million in 2008 and $372.4 million in 2007 excluded from amortization	4,162,839	4,020,448
Gathering systems	236,432	158,604
Gas in underground storage	13,349	13,349
Other	97,752	85,983
	4,510,372	4,278,384
Less: Accumulated depreciation, depletion and amortization	1,392,380	1,200,754
	3,117,992	3,077,630
Assets Held For Sale (see Note 4)	142,971	143,234
Other Assets	70,504	38,511
Total Assets	$ 4,137,460	$ 3,622,716

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

LIABILITIES AND STOCKHOLDERS' EQUITY

	June 30, 2008	December 31, 2007
	(in thousands)	
Current Liabilities		
Short-term debt	$ 61,200	$ 1,200
Accounts payable	427,702	313,070
Taxes payable	56,981	5,087
Interest payable	22,288	2,213
Advances from partners	43,188	32,005
Hedging liability - FAS 133	519,313	8,598
Current deferred income taxes	-	20,909
Current liabilities associated with assets held for sale (see Note 4)	32,633	39,118
Other	6,144	8,695
Total current liabilities	1,169,449	430,895
Long-Term Debt	674,800	977,600
Other Liabilities		
Deferred income taxes	450,089	479,196
Long-term hedging liability	301,668	15,186
Pension liability	11,352	12,268
Liabilities associated with assets held for sale (see Note 4)	17,005	15,417
Other	39,377	35,084
	819,491	557,151
Commitments and Contingencies		
Minority Interest in Partnership	10,718	10,570
Stockholders' Equity		
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 342,786,381 shares in 2008 and 341,581,672 in 2007 (1)	3,428	3,416
Additional paid-in capital(1)	798,750	752,369
Retained earnings	1,127,610	882,031
Accumulated other comprehensive income (loss)	(462,061)	13,348
Common stock in treasury, 224,594 shares in 2008 and 222,774 in 2007(1)	(4,725)	(4,664)
	1,463,002	1,646,500
Total Liabilities and Stockholders' Equity	$ 4,137,460	$ 3,622,716

(1) 2007 restated to reflect the two-for-one stock split effected on March 25, 2008.

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

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

	For the six months ended June 30, 2008	For the six months ended June 30, 2007
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 245,579	$ 98,582
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	196,411	122,887
Deferred income taxes	104,017	60,421
Unrealized loss on derivatives	20,345	4,589
Stock-based compensation expense	5,839	2,648
Gain on sale of property, plant and equipment	(392)	-
Minority interest in partnership	148	59
Change in assets and liabilities:		
Accounts receivable	(112,355)	(21,786)
Inventories	1,790	811
Under/over-recovered purchased gas costs	(2,922)	4,101
Accounts payable	84,805	14,403
Taxes payable	51,131	(4,876)
Interest payable	19,953	358
Advances from partners and customer deposits	11,003	(1,161)
Deferred tax benefit - stock options	(39,332)	(17,764)
Other assets and liabilities	2,232	(5,054)
Net cash provided by operating activities	588,252	258,218
Cash Flows From Investing Activities		
Capital investments	(812,421)	(704,583)
Proceeds from sale of property, plant and equipment	590,513	2,712
Other items	(296)	158
Net cash used in investing activities	(222,204)	(701,713)
Cash Flows From Financing Activities		
Debt retirement	(600)	(600)
Payments on revolving long-term debt	(1,843,600)	(355,200)
Borrowings under revolving long-term debt	1,001,400	715,300
Proceeds from issuance of long-term debt	600,000	-
Debt issuance costs and revolving credit facility costs	(8,895)	(1,275)
Excess tax benefit for stock-based compensation	39,332	17,764
Change in bank drafts outstanding	19,643	21,056
Proceeds from exercise of common stock options	2,067	3,834
Net cash provided by (used in) financing activities	(190,653)	400,879
Increase (decrease) in cash and cash equivalents	175,395	(42,616)
Cash and cash equivalents at beginning of year (1)	1,832	42,927
Cash and cash equivalents at end of period (1)	$ 177,227	$ 311

(1) Cash and cash equivalents includes amounts classified as "held for sale." See Note 4 for additional information.

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[1] Shares Issued	Common Stock[1] Amount	Additional Paid-In Capital[1]	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
				(in thousands)			
Balance at December 31, 2007	341,578	$ 3,416	$ 752,369	$ 882,031	$ 13,348	$ (4,664)	$ 1,646,500
Comprehensive income:							
Net income	-	-	-	245,579	-	-	245,579
Change in value of derivatives	-	-	-	-	(475,828)	-	(475,828)
Change in value of pension liability	-	-	-	-	419	-	419
Total comprehensive income (loss)							(229,830)
Tax benefit for stock-based compensation	-	-	39,332	-	-	-	39,332
Stock-based compensation - FAS 123(R)	-	-	4,912	-	-	-	4,912
Exercise of stock options	1,148	11	2,056	-	-	-	2,067
Issuance of restricted stock	78	1	(1)	-	-	-	-
Cancellation of restricted stock	(22)	-	-	-	-	-	-
Issuance of stock awards	4	-	82	-	-	-	82
Treasury stock - non-qualified plan	-	-	-	-	-	(61)	(61)
Balance at June 30, 2008	342,786	$ 3,428	$ 798,750	$ 1,127,610	$ (462,061)	$ (4,725)	$ 1,463,002

(1) 2007 restated to reflect the two-for-one stock split effected on March 25, 2008.

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

	For the three months ended June 30, 2008	For the three months ended June 30, 2007	For the six months ended June 30, 2008	For the six months ended June 30, 2007
	(in thousands)			
Net income	$ 136,550	$ 47,594	$ 245,579	$ 98,582
Change in value of derivatives				
Current period reclassification to earnings	47,358	(1,798)	35,646	(14,054)
Current period ineffectiveness	17,822	(114)	26,281	4,809
Current period change in derivative instruments	(348,873)	40,130	(537,755)	(10,701)
Total change in value of derivatives	(283,693)	38,218	(475,828)	(19,946)
Current period change in pension and other postretirement liability	210	-	419	-
Comprehensive income (loss), end of period	$ (146,933)	$ 85,812	$ (229,830)	$ 78,636

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
June 30, 2008

(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, 2007 (the "2007 Annual Report on Form 10-K").

In February 2008, the Board of Directors declared a two-for-one stock split with respect to the Company’s common stock, which was effected in March 2008. All historical per share information in the financial statements and footnotes has been adjusted, as necessary, to reflect the two-for-one stock split.

Certain reclassifications have been made to the prior years’ financial statements to conform to the 2008 presentation. The effects of the reclassifications were not material to the Company’s consolidated financial statements.

(2) 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 June 30, 2008 and 2007, the Company’s unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At June 30, 2008, the ceiling value of the Company’s reserves was calculated based upon quoted market prices of $13.10 per Mcf for Henry Hub gas and $136.50 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at June 30, 2008, decreased the calculated ceiling value by approximately $475.4 million (net of tax). The Company had approximately 237.5 Bcf of future gas production hedged at June 30, 2008. Decreases in market prices from June 30, 2008 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 six months ended June 30, 2008 and 2007, respectively. For the periods ended June 30, 2007, all shares and per share amounts (including exercise prices for assumed exercises of stock options) have been restated to reflect the two-for-one stock split effected on March 25, 2008:

	For the three months ended June 30,		For the six months ended June 30,	
	2008	2007	2008	2007
Net Income (in thousands)	$ 136,550	$ 47,594	$ 245,579	$ 98,582
Number of Common Shares:				
Weighted average outstanding	341,402,888	338,933,824	341,233,574	338,073,050
Issued upon assumed exercise of outstanding stock options	4,662,932	5,578,220	4,628,168	6,035,314
Effect of issuance of nonvested restricted common shares	485,378	489,038	426,101	429,440
Weighted average and potential dilutive outstanding(1)	346,551,198	345,001,082	346,287,843	344,537,804
Net Income per Common Share:				
Basic	$ 0.40	$ 0.14	$ 0.72	$ 0.29
Diluted	$ 0.39	$ 0.14	$ 0.71	$ 0.29

(1) Options for 387,659 shares for the six months ended June 30, 2008 and 419,460 shares for the comparable period of 2007 (as adjusted for the stock split) were excluded from the calculations because they would have had an antidilutive effect. Additionally, 16,189 shares of restricted stock for the six months ended June 30, 2008 and 400 shares of restricted stock for the comparable period of 2007 (as adjusted for the stock split) were excluded from the calculations because they would have had an antidilutive effect.

(4) ASSETS HELD FOR SALE

In November 2007, the Company entered into an agreement to sell all of the capital stock of Arkansas Western Gas Company (“AWG”) for $224 million plus working capital. On July 1, 2008, the transaction was closed and the Company received approximately $230 million, subject to post-closing adjustments. The Company expects to record a gain on the sale of approximately $55 million in the third quarter of 2008. Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144), requires that long-lived assets or disposal groups to be sold should be classified as “held for sale” in the period in which certain criteria are met. Accordingly, the assets and liabilities of AWG have been presented as “held for sale” in the June 30, 2008 and December 31, 2007 balance sheets.

The following table presents the assets and liabilities of AWG as of June 30, 2008 and December 31, 2007:

	June 30, 2008	December 31, 2007
	(in thousands)	
Current Assets:		
Cash	$ 136	$ 1,105
Accounts receivable	13,067	29,826
Inventory	24,029	23,737
Hedging asset – FAS 133	—	2,387
Deferred income tax benefit	4,504	—
Other current assets	1,190	1,822
	$ 42,926	$ 58,877
Long-term assets, including property, plant and equipment, net of accumulated depreciation and amortization	$ 142,971	$ 143,234
Current Liabilities:		
Accounts payable	$ 3,540	$ 3,700
Interest payable	48	171
Taxes payable	6,784	7,547
Deferred gas purchases	13,367	16,289
Customer deposits	7,371	7,551
Hedging liability – FAS 133	—	2,387
Other current liabilities	1,523	1,473
	$ 32,633	$ 39,118
Long-term Liabilities:		
Deferred income taxes	$ 16,690	$ 15,066
Other long-term liabilities	315	351
	$ 17,005	$ 15,417

(5) DEBT

Debt balances as of June 30, 2008 and December 31, 2007 consisted of the following:

	June 30, 2008	December 31, 2007
	(in thousands)	
Short-term debt:		
7.625% Senior Notes due 2027, putable at the holders' option in 2009	$ 60,000	$ —
7.15% Senior Notes due 2018	1,200	1,200
Total short-term debt	61,200	1,200
Long-term debt:		
Variable rate unsecured revolving credit facility, expires February 2012	—	842,200
7.5% Senior Notes due 2018	600,000	—
7.625% Senior Notes due 2027, putable at the holders' option in 2009	—	60,000
7.21% Senior Notes due 2017	40,000	40,000
7.15% Senior Notes due 2018	34,800	35,400
Total long-term debt	674,800	977,600
Total debt	$ 736,000	$ 978,800

On January 16, 2008, the Company issued $600 million of 7.5% Senior Notes due 2018 in a private placement. The 7.5% Senior Notes are redeemable at the Company's election, in whole or in part, at any time at a redemption price equal to the greater of: (1) 100% of the principal amount of the notes to be redeemed then outstanding; and (2) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the redemption date on a semiannual basis as determined in accordance with the indenture, plus 50 basis points, plus, in either of such cases, accrued and unpaid interest to the date of redemption on the notes to be redeemed. In addition, if the Company undergoes a "change of control," as defined in the indenture, holders of the 7.5% Senior Notes will have the option to require the Company to purchase all or any portion of the notes at a purchase price equal to 101% of the principal amount of the notes to be purchased plus any accrued and unpaid interest to, but excluding, the change of control date. Payment obligations with respect to the 7.5% Senior Notes are currently guaranteed by the Company's subsidiaries, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services Company (SES), which guarantees may be unconditionally released in certain circumstances. As a result of the issuance of the guarantees of the 7.5% Senior Notes, and in order for all of the Company's senior notes to rank equally, on May 2, 2008, the Company and its subsidiaries, SEECO, SEPCO and SES, entered into supplemental indenture agreements with the trustees under the indentures relating to the Company's 7.625% Medium-Term Notes due 2027, 7.125% Fixed Rate Notes due October 10, 2017, 7.35% Fixed Rate Notes due October 2, 2017 and 7.15% Notes due 2018, pursuant to which SEECO, SEPCO and SES became guarantors of such notes to the same extent to which such subsidiaries have guaranteed the

Company’s 7.5% Senior Notes. Please refer to Note 6, "Condensed Consolidating Financial Information" in this Form 10-Q for additional information. The indentures governing the Company’s senior notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets.

In October 2007, the Company amended its unsecured revolving credit facility increasing the borrowing capacity to $1.0 billion. The amendment also provides that 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. 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, SEECO, SEPCO, and SES and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. At June 30, 2008, the Company’s capital structure consisted of 33% debt and 67% equity and it was in compliance with the covenants of its debt agreements.

(6) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company is providing condensed consolidating financial information for SEECO, SEPCO and SES, its subsidiaries that are guarantors of the Company’s registered public debt, and for its other subsidiaries that are not guarantors. These wholly owned subsidiary guarantors have jointly and severally, fully and unconditionally guaranteed the Company’s 7.625% Senior Notes and 7.21% Senior Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated to any future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors.

The Company has not presented separate financial and narrative information for each of the subsidiary guarantors because it believes that such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantees. The following condensed consolidating financial information summarizes the results of operations, financial position and cash flows for the Company’s guarantor and non-guarantor subsidiaries.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

Three months ended June 30, 2008:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$ 577,034	$ 64,105	$ (36,769)	$ 604,370
Operating costs and expenses:					
Gas purchases	—	212,903	20,464	(20,934)	212,433
Operating expenses	—	28,394	17,324	(15,688)	30,030
General and administrative expenses	—	19,416	6,472	(147)	25,741
Depreciation, depletion and amortization	—	93,762	4,389	—	98,151
Taxes, other than income taxes	—	7,206	1,523	—	8,729
Total operating costs and expenses	—	361,681	50,172	(36,769)	375,084
Operating income	—	215,353	13,933	—	229,286
Other income (loss)	—	328	(159)	—	169
Equity in earnings of subsidiaries	136,550	—	—	(136,550)	—
Interest expense	—	4,273	4,724	—	8,997
Income before income taxes and minority interest	136,550	211,408	9,050	(136,550)	220,458
Minority interest in partnership	—	(215)	—	—	(215)
Provision for income taxes	—	80,254	3,439	—	83,693
Net income	$ 136,550	$ 130,939	$ 5,611	$ (136,550)	$ 136,550

Three months ended June 30, 2007:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$ 252,273	$ 37,515	$ (19,706)	$ 270,082
Operating costs and expenses:					
Gas purchases	—	75,399	16,187	(14,671)	76,915
Operating expenses	—	13,753	11,624	(4,892)	20,485
General and administrative expenses	—	12,771	5,307	(143)	17,935
Depreciation, depletion and amortization	—	63,635	2,800	—	66,435
Taxes, other than income taxes	—	5,278	1,028	—	6,306
Total operating costs and expenses	—	170,836	36,946	(19,706)	188,076
Operating income	—	81,437	569	—	82,006
Other income (loss)	—	24	(149)	—	(125)
Equity in earnings of subsidiaries	47,594	—	—	(47,594)	—
Interest expense	—	3,512	1,494	—	5,006
Income before income taxes and minority interest	47,594	77,949	(1,074)	(47,594)	76,875
Minority interest in partnership	—	(111)	—	—	(111)
Provision (benefit) for income taxes	—	29,579	(409)	—	29,170
Net income	$ 47,594	$ 48,259	$ (665)	$ (47,594)	$ 47,594

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS (Continued)
(Unaudited)

Six months ended June 30, 2008:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$1,027,645	$ 170,825	$ (69,994)	$1,128,476
Operating costs and expenses:					
Gas purchases	—	359,776	79,120	(42,116)	396,780
Operating expenses	—	50,296	31,319	(27,589)	54,026
General and administrative expenses	—	37,115	12,655	(289)	49,481
Depreciation, depletion and amortization	—	186,769	8,479	—	195,248
Taxes, other than income taxes	—	13,140	3,005	—	16,145
Total operating costs and expenses	—	647,096	134,578	(69,994)	711,680
Operating income	—	380,549	36,247	—	416,796
Other income (loss)	—	441	(265)	—	176
Equity in earnings of subsidiaries	245,579	—	—	(245,579)	—
Interest expense	—	12,865	7,661	—	20,526
Income before income taxes and minority interest	245,579	368,125	28,321	(245,579)	396,446
Minority interest in partnership	—	(350)	—	—	(350)
Provision for income taxes	—	139,755	10,762	—	150,517
Net income	$ 245,579	$ 228,020	$ 17,559	$ (245,579)	$ 245,579

Six months ended June 30, 2007:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$ 473,752	$ 121,631	$ (40,649)	$ 554,734
Operating costs and expenses:					
Gas purchases	—	139,254	70,404	(31,545)	178,113
Operating expenses	—	26,159	23,179	(8,816)	40,522
General and administrative expenses	—	24,124	10,847	(288)	34,683
Depreciation, depletion and amortization	—	116,376	5,844	—	122,220
Taxes, other than income taxes	—	11,250	2,181	—	13,431
Total operating costs and expenses	—	317,163	112,455	(40,649)	388,969
Operating income	—	156,589	9,176	—	165,765
Other income (loss)	—	94	(198)	—	(104)
Equity in earnings of subsidiaries	98,582	—	—	(98,582)	—
Interest expense	—	3,605	2,859	—	6,464
Income before income taxes and minority interest	98,582	153,078	6,119	(98,582)	159,197
Minority interest in partnership	—	(194)	—	—	(194)
Provision for income taxes	—	58,096	2,325	—	60,421
Net income	$ 98,582	$ 94,788	$ 3,794	$ (98,582)	$ 98,582

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

June 30, 2008:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
ASSETS					
Cash and cash equivalents	$ 213,929	$ (37,368)	$ 530	$ —	$ 177,091
Accounts receivable	357	302,731	3,706	—	306,794
Inventories, at average cost	38	27,141	635	—	27,814
Current assets held for sale (see Note 4)	—	—	42,926	—	42,926
Other	7,087	243,829	452	—	251,368
Total current assets	221,411	536,333	48,249	—	805,993
Intercompany receivables/note	1,170,559	(930,169)	(166,021)	(74,369)	—
Investments	—	8,810	(8,809)	(1)	—
Property, plant and equipment, at cost	50,865	4,198,844	260,663	—	4,510,372
Accumulated depreciation, depletion and amortization	(26,819)	(1,333,839)	(31,722)	—	(1,392,380)
Net property, plant and equipment	24,046	2,865,005	228,941	—	3,117,992
Investments in subsidiaries (equity method)	890,864	—	—	(890,864)	—
Assets held for sale (see Note 4)	—	—	142,971	—	142,971
Other assets	15,760	34,891	19,853	—	70,504
Total assets	$ 2,322,640	$ 2,514,870	$ 265,184	$ (965,234)	$ 4,137,460
LIABILITIES AND STOCKHOLDERS' EQUITY					
Accounts and notes payable	$ 248,944	$ 307,727	$ 23,200	$ (11,700)	$ 568,171
Current liabilities associated with assets held for sale (see Note 4)	—	—	32,633	—	32,633
Other current liabilities	1,494	565,749	1,402	—	568,645
Total current liabilities	250,438	873,476	57,235	(11,700)	1,169,449
Long-term debt	674,800	—	—	—	674,800
Indebtedness to related parties – noncurrent	—	—	62,670	(62,670)	—
Liabilities associated with assets held for sale (see Note 4)	—	—	17,005	—	17,005
Other liabilities	29,444	317,462	5,491	—	352,397
Commitments and contingencies					
Deferred income taxes	(95,044)	538,846	6,287	—	450,089
Minority interest in partnership	—	10,718	—	—	10,718
Total liabilities	859,638	1,740,502	148,688	(74,370)	2,674,458
Stockholders' equity	1,463,002	774,368	116,496	(890,864)	1,463,002
Total liabilities and stockholders' equity	$ 2,322,640	$ 2,514,870	$ 265,184	$ (965,234)	$ 4,137,460

CONDENSED CONSOLIDATING BALANCE SHEETS (Continued)
(Unaudited)

December 31, 2007:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
ASSETS					
Cash	$ 10,040	$ (9,607)	$ 294	$ —	$ 727
Accounts receivable	346	173,772	3,562	—	177,680
Inventories, at average cost	—	33,034	—	—	33,034
Current assets held for sale (see Note 4)	—	—	58,877	—	58,877
Other	8,270	83,572	1,181	—	93,023
Total current assets	18,656	280,771	63,914	—	363,341
Intercompany receivables/note	1,555,926	(1,313,826)	(148,949)	(93,151)	—
Investments	—	8,444	(8,443)	(1)	—
Property, plant and equipment, at cost	47,623	4,016,483	214,278	—	4,278,384
Accumulated depreciation, depletion and amortization	(23,772)	(1,149,713)	(27,269)	—	(1,200,754)
Net property, plant and equipment	23,851	2,866,770	187,009	—	3,077,630
Investments in subsidiaries (equity method)	1,120,985	—	—	(1,120,985)	—
Assets held for sale (see Note 4)	—	—	143,234	—	143,234
Other assets	7,518	14,277	16,716	—	38,511
Total assets	$ 2,726,936	$ 1,856,436	$ 253,481	$ (1,214,137)	$ 3,622,716
LIABILITIES AND STOCKHOLDERS' EQUITY					
Accounts and notes payable	$ 105,259	$ 220,923	$ 9,503	$ (14,115)	$ 321,570
Current liabilities associated with assets held for sale (see Note 4)	—	—	39,118	—	39,118
Other current liabilities	1,368	67,530	1,309	—	70,207
Total current liabilities	106,627	288,453	49,930	(14,115)	430,895
Long-term debt	977,600	—	—	—	977,600
Indebtedness to related parties – noncurrent	—	—	79,037	(79,037)	—
Liabilities associated with assets held for sale (see Note 4)	—	—	15,417	—	15,417
Other liabilities	26,091	30,845	5,602	—	62,538
Commitments and contingencies					
Deferred income taxes	(29,882)	508,041	1,037	—	479,196
Minority interest in partnership	—	10,570	—	—	10,570
Total liabilities	1,080,436	837,909	151,023	(93,152)	1,976,216
Stockholders' equity	1,646,500	1,018,527	102,458	(1,120,985)	1,646,500
Total liabilities and stockholders' equity	$ 2,726,936	$ 1,856,436	$ 253,481	$ (1,214,137)	$ 3,622,716

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

Six months ended June 30, 2008:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Net cash provided by operating activities	$ (4)	$ 549,753	$ 38,503	$ —	$ 588,252
Investing activities:					
Capital investments	(3,286)	(729,252)	(79,883)	—	(812,421)
Proceeds from sale of property, plant and equipment	—	542,092	48,421	—	590,513
Other items	3,047	3,999	(7,342)	—	(296)
Net cash used in investing activities	(239)	(183,161)	(38,804)	—	(222,204)
Financing activities:					
Intercompany activities	394,775	(394,918)	143	—	—
Payments on revolving long-term debt	(1,843,600)	—	—	—	(1,843,600)
Borrowings under revolving long-term debt	1,001,400	—	—	—	1,001,400
Proceeds from issuance of long-term debt	600,000	—	—	—	600,000
Excess tax benefit for stock-based compensation	39,332	—	—	—	39,332
Other items	12,225	565	(575)	—	12,215
Net cash used in financing activities	204,132	(394,353)	(432)	—	(190,653)
Increase (decrease) in cash and cash equivalents	203,889	(27,761)	(733)	—	175,395
Cash and cash equivalents at beginning of year(1)	10,040	(9,607)	1,399	—	1,832
Cash and cash equivalents at end of period(1)	$ 213,929	$ (37,368)	$ 666	$ —	$ 177,227

Six months ended June 30, 2007:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Net cash provided by operating activities	$ 2,421	$ 231,631	$ 24,166	$ —	$ 258,218
Investing activities:					
Capital investments	(4,562)	(641,477)	(58,544)	—	(704,583)
Proceeds from sale of property, plant and equipment	—	2,712	—	—	2,712
Other items	2,119	(2,069)	108	—	158
Net cash used in investing activities	(2,443)	(640,834)	(58,436)	—	(701,713)
Financing activities:					
Intercompany activities	(434,271)	399,626	34,645	—	—
Payments on revolving long-term debt	(355,200)	—	—	—	(355,200)
Borrowings under revolving long-term debt	715,300	—	—	—	715,300
Proceeds from issuance of long-term debt	—	—	—	—	—
Excess tax benefit for stock-based compensation	17,764	—	—	—	17,764
Other items	23,015	426	(426)	—	23,015
Net cash provided by financing activities	(33,392)	400,052	34,219	—	400,879
Increase (decrease) in cash and cash equivalents	(33,414)	(9,151)	(51)	—	(42,616)
Cash and cash equivalents at beginning of year(1)	46,951	(4,424)	400	—	42,927
Cash and cash equivalents at end of period(1)	$ 13,537	$ (13,575)	$ 349	$ —	$ 311

(1) Cash and cash equivalents includes amounts classified as “held for sale.” See Note 4 for additional information.

(7) DERIVATIVES AND RISK MANAGEMENT

The Company enters into various types of derivative instruments for a portion of its projected gas and oil sales to reduce its exposure to market price volatility for natural gas and oil. At June 30, 2008, 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, FAS 149 and FAS 157 (see Note 8 below regarding the adoption of FAS 157 in the first quarter of 2008), 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 requirements of FAS 133 cannot be recorded as a component of other comprehensive income. The Company’s hedging practices are summarized in Note 9 of the Notes to Consolidated Financial Statements in the 2007 Annual Report on Form 10-K.

At June 30, 2008, the Company's net liability recorded on the balance sheet related to its hedging activities was $740.1 million. Additionally, at June 30, 2008, the Company recorded a loss to other comprehensive income of $451.2 million related to its hedging activities which resulted in a current deferred income tax benefit of $177.6 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Assuming the market prices of gas futures as of June 30, 2008 remain unchanged, the Company would expect to transfer an aggregate after-tax loss of approximately $289.7 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 loss of $457.6 million ($283.7 million after tax) compared to a gain of $61.6 million ($38.2 million after tax) for the three months ended June 30, 2008 and 2007, respectively, and a loss of $767.5 million ($475.8 million after tax) compared to a loss of $32.2 million ($19.9 million after tax) for the six months ended June 30, 2008 and 2007, respectively. The Company recorded decreases of $12.7 million and $20.3 million in gas sales revenues during the second quarter and first half of 2008, respectively, related to the ineffectiveness of cash flow hedges and changes in unrealized gains or losses for derivatives that were not accounted for as cash flow hedges, compared to decreases of $2.1 million and $4.6 million for the same periods in 2007, respectively. Additional volatility in earnings and other comprehensive income may occur in the future as a result of the application of FAS 133.

(8) FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company partially adopted Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" (FAS 157), which defines fair value, provides a framework for measuring fair value under generally accepted accounting principles (GAAP) and expands required disclosures about fair value measurements. The Company also adopted Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" (FAS 159), on January 1, 2008, which allows an entity the irrevocable option to elect fair value for the initial and subsequent measurement for certain financial assets and liabilities on a contract-by-contract basis. The Company does not plan to elect to use the fair value option under FAS 159 for any of its financial instruments that are not currently measured at fair value.

FAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels. Level 1 valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority. Level 2 fair value valuations rely on quoted market information for the calculation of fair market value. Level 3 valuations are internal estimates and have the lowest priority. Per FAS 157, the Company has classified its derivatives into these levels depending upon the data relied on to determine the fair values. The Company’s natural gas swaps are estimated using internal discounted cash flow calculations using the NYMEX futures index and are designated as Level 2. The fair values of collars and natural gas basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves or quotes obtained from counterparties to the agreements and are designated as Level 3. Assets and liabilities measured at fair value on a recurring basis are summarized below:

	June 30, 2008 (in thousands)			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets/Liabilities at Fair Value
Derivative assets	$ —	$ 1,061	$ 58,550	$ 59,611
Derivative liabilities	—	(535,980)	(263,752)	(799,732)
Total	$ —	$ (534,919)	$ (205,202)	$ (740,121)

The tables below present reconciliations for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the second quarter and first half of 2008. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the tables consist of net derivatives valued using pricing models incorporating assumptions that, in management’s judgment, reflect the assumptions a marketplace participant would have used at June 30, 2008.

Total Gains and Losses for the three months ended June 30, 2008 (Level 3 Only)

	Net Derivatives (in thousands)
Balance at April 1, 2008	$ (53,513)
Total gains or losses (realized/unrealized):	
Included in earnings[1]	4,651
Included in other comprehensive income (loss)	(156,208)
Purchases, issuances, and settlements	(132)
Transfers in to/out of Level 3	—
Balance at June 30, 2008	$ (205,202)
Change in unrealized gains (losses) included in earnings relating to derivates still held as of June 30, 2008	$ 4,519

Total Gains and Losses for the six months ended June 30, 2008 (Level 3 Only)

	Net Derivatives (in thousands)
Balance at January 1, 2008	$ 32,767
Total gains or losses (realized/unrealized):	
Included in earnings[1]	13,984
Included in other comprehensive income (loss)	(240,586)
Purchases, issuances, and settlements	(11,367)
Transfers in to/out of Level 3	—
Balance at June 30, 2008	$ (205,202)
Change in unrealized gains (losses) included in earnings relating to derivates still held as of June 30, 2008	$ 2,617

(1) Reported in gas sales revenue in the consolidated statements of operations.

(9) SEGMENT INFORMATION

The Company's three reportable business segments for the reportable periods presented, 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 by AWG. Effective as of the July 1, 2008 closing of the sale of AWG, the Company no longer has any natural gas distribution operations.

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 2007 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 (loss) and minority interest in partnership. The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration And Production	Midstream Services	Natural Gas Distribution	Other		Total
			(in thousands)			
Three months ended June 30, 2008:						
Revenues from external customers	$ 353,258	$ 217,639	$ 33,473	$ —		$ 604,370
Intersegment revenues	24,467	422,119	46	112		446,744
Operating income (loss)	215,086	15,002	(857)	55		229,286
Interest and other income (loss)(1)	327	—	(163)	5		169
Depreciation, depletion and amortization expense	94,031	2,370	1,713	37		98,151
Interest expense(1)	4,807	3,081	1,109	—		8,997
Provision (benefit) for income taxes(1)	79,949	4,530	(809)	23		83,693
Assets	3,206,932	475,507	185,897	269,124	(2)	4,137,460
Capital investments(3)	362,821	47,878	2,583	2,260		415,542
Three months ended June 30, 2007:						
Revenues from external customers	$ 168,434	$ 74,079	$ 27,569	$ —		$ 270,082
Intersegment revenues	13,364	159,588	36	112		173,100
Operating income (loss)	81,352	2,310	(1,706)	50		82,006
Interest and other income (loss)(1)	21	—	(153)	7		(125)
Depreciation, depletion and amortization expense	64,039	744	1,615	37		66,435
Interest expense(1)	3,546	381	1,079	—		5,006
Provision (benefit) for income taxes(1)	29,533	733	(1,117)	21		29,170
Assets	2,501,659	187,779	175,296	64,260	(2)	2,928,994
Capital investments(3)	369,125	23,660	3,339	717		396,841
Six months ended June 30, 2008:						
Revenues from external customers	$ 650,357	$ 363,162	$ 114,957	$ —		$ 1,128,476
Intersegment revenues	39,385	681,921	2,753	224		724,283
Operating income	380,796	25,163	10,733	104		416,796
Interest and other income (loss)(1)	441	—	(270)	5		176
Depreciation, depletion and amortization expense	187,337	4,407	3,431	73		195,248
Interest expense(1)	13,577	4,632	2,317	—		20,526
Provision for income taxes(1)	139,578	7,802	3,095	42		150,517
Assets	3,206,932	475,507	185,897	269,124	(2)	4,137,460
Capital investments(3)	739,335	79,323	3,574	3,168		825,400
Six months ended June 30, 2007:						
Revenues from external customers	$ 319,889	$ 130,398	$ 104,447	$ —		$ 554,734
Intersegment revenues	23,170	281,858	152	224		305,404
Operating income	155,662	2,321	7,675	107		165,765
Interest and other income (loss)(1)	93	—	(204)	7		(104)
Depreciation, depletion and amortization expense	117,113	1,786	3,249	72		122,220
Interest expense(1)	3,639	381	2,444	—		6,464
Provision for income taxes(1)	57,730	737	1,910	44		60,421
Assets	2,501,659	187,779	175,296	64,260	(2)	2,928,994
Capital investments(3)	670,323	45,280	5,943	2,548		724,094

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

(2) Other assets include the Company's investment in cash equivalents for 2008, and for 2008 and 2007 corporate assets not allocated to segments and assets for non-reportable segments.
(3) Capital investments include a reduction of $6.8 million and an increase of $10.0 million for the three- and six-month periods ended June 30, 2008, respectively, and increases of $64.0 million and $17.7 million for the three- and six-month periods ended June 30, 2007, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $389.0 million and $142.1 million for the second quarters of 2008 and 2007, respectively, and $628.1 million and $249.1 million for the six months ended June 30, 2008 and 2007, 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 terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures and prepaid debt and other 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.

(10) INTEREST AND INCOME TAXES PAID

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

	For the six months ended June 30, 2008	For the six months ended June 30, 2007
	(in thousands)	
Interest payments	$ 12,669	$ 11,080
Income tax payments	$ —	$ —

As a result of the gains on the proceeds received from the sales of Fayetteville Shale acreage, the utility and certain oil and gas properties, the Company expects to be subject to future alternative minimum tax payments in 2008.

(11) CONTINGENCIES AND COMMITMENTS

Operating Commitments

The Company has various operating commitments in the normal course of its operations. In the first quarter of 2008, the Company exercised the first of its three options to increase the volumes to be transported on each of the two pipeline laterals and related facilities being constructed by Texas Gas Transmission, LLC for which the Company is the anchor shipper, and subsequent to the second quarter, the Company exercised its remaining options. Once effective, which can occur no earlier than April 1, 2010, the exercised options will result in aggregate commitments of 800,000 MMBtu per day on the Fayetteville Lateral and 640,000 MMBtu per day on the Greenville Lateral. Other than the increase in pipeline volume commitments, the Company has not made any new material operating commitments or modified its disclosed material commitments from those disclosed in the 2007 Annual Report on Form 10-K.

Environmental Risk

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

Litigation

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

(12) 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 10 of the Notes to Consolidated Financial Statements included in Item 8 of the 2007 Annual Report on Form 10-K.

For the second quarter and first six months of 2008, the Company recorded compensation cost of $0.7 million and $1.5 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.3 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 $0.2 million related to stock options for the six months ended June 30, 2008, compared to a deferred tax benefit of $0.5 million for the comparable period in 2007. A total of $5.9 million of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods. For the second quarter and first six months of 2007, the Company recorded compensation cost of $0.5 million and $1.3 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.1 million and $0.3 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 second quarter and first six months of 2008, the Company recorded compensation cost of $0.8 and $1.7 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $0.6 million and $1.3 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 June 30, 2008, there was $13.8 million of total unrecognized compensation cost related to nonvested shares of restricted stock. For the second quarter and first six months of 2007, the Company recorded compensation cost of $0.6 and $1.3 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $0.4 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 half of 2008 and provide information for options outstanding at June 30, 2008. The number of options and exercise prices have been restated, as necessary, to reflect the two-for-one stock split effected on March 25, 2008:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2007	8,552,874	$ 4.81
Granted	31,500	36.68
Exercised	(1,147,825)	1.80
Forfeited or expired	(3,200)	27.18
Outstanding at June 30, 2008	7,433,349	$ 5.41
Exercisable at June 30, 2008	6,565,306	$ 2.99

During the first six months of 2008, there were 31,500 options granted, compared to no options granted during the first six months of 2007. The total intrinsic value of options exercised during the first six months of 2008 and 2007 was $43.6 million and $48.6 million, respectively. Associated with the exercise of stock options, the Company recorded a tax benefit of $39.3 million in the first six months of 2008, compared to $17.8 million in the first six months of 2007. The tax benefits were recorded as increases in additional paid-in capital.

	Options Outstanding				Options Exercisable		
Range of Exercise Prices	Options Outstanding at June 30, 2008	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at June 30, 2008	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$0.75 - $1.00	2,336,776	$ 0.91	2.3		2,336,776	$ 0.91	
$1.01 - $2.50	1,957,166	1.38	4.0		1,957,166	1.38	
$2.51 - $6.00	1,218,910	2.76	5.5		1,218,910	2.76	
$6.01 - $17.75	1,029,183	10.38	3.8		894,831	9.29	
$17.76 - $44.34	891,314	23.91	5.9		157,623	20.09	
	7,433,349	$ 5.41	3.9	$ 313,723	6,565,306	$ 2.99	$ 292,918

The following table summarizes restricted stock activity for the first half of 2008. The number of shares and the grant date fair values have been restated, as necessary, to reflect the two-for-one stock split effected on March 25, 2008:

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2007	791,030	$ 19.89
Granted	78,070	41.35
Vested	(28,176)	15.28
Forfeited	(21,528)	21.70
Unvested shares at June 30, 2008	819,396	$ 22.05

(13) 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 six-month periods ended June 30, 2008 and 2007:

	Pension Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Service cost	$ 1,408	$ 996	$ 2,816	$ 1,992
Interest cost	1,208	1,061	2,418	2,121
Expected return on plan assets	(1,254)	(1,139)	(2,509)	(2,279)
Amortization of prior service cost	122	118	244	237
Amortization of net loss	175	115	349	230
Net periodic benefit cost	$ 1,659	$ 1,151	$ 3,318	$ 2,301

	Postretirement Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Service cost	$ 165	$ 105	$ 330	$ 209
Interest cost	78	54	155	108
Expected return on plan assets	(24)	(20)	(48)	(40)
Amortization of transition obligation	22	21	44	43
Amortization of prior service cost	3	—	6	—
Amortization of net loss	17	5	34	10
Net periodic benefit cost	$ 261	$ 165	$ 521	$ 330

The Company currently expects to contribute $8.1 million to the pension plans and $0.4 million to the postretirement benefit plans in 2008. As of June 30, 2008, $3.6 million has been contributed to the pension plans and $0.2 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 June 30, 2008, 224,594 shares were accounted for as treasury stock, compared to 222,774 shares at December 31, 2007.

(14) 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 six-month period ended June 30, 2008 and for the year ended December 31, 2007:

Asset retirement obligation at January 1	$ 12,114	$ 10,545
Accretion of discount	259	481
Obligations incurred	1,361	2,236
Obligations settled/removed	(1,986)	(499)
Revisions of estimates	—	(649)
Asset retirement obligation at June 30, 2008 and December 31, 2007	$ 11,748	$ 12,114
Current liability	602	720
Long-term liability	11,146	11,394
Asset retirement obligation at June 30, 2008 and December 31, 2007	$ 11,748	$ 12,114

(15) INVENTORY

Inventory recorded in current assets includes $15.0 million at June 30, 2008, and $25.0 million at December 31, 2007, for gas in underground storage owned by the Company's E&P segment, and $12.8 million at June 30, 2008, and $8.1 million at December 31, 2007, for tubulars and other equipment used in the Company's E&P segment. Additionally, the Natural Gas Distribution segment had current gas in underground storage of $21.8 million at June 30, 2008, and $21.6 million at December 31, 2007, that was classified in the balance sheets as "Current Assets Held for Sale."

Other assets includes $19.9 million at June 30, 2008, and $16.7 million at December 31, 2007, for non-current inventory held by the Midstream Services segment consisting primarily of tubulars that will be used to construct gathering systems for the Fayetteville Shale play.

(16) DIVESTITURES AND SUBSEQUENT EVENTS

In the second quarter of 2008, the Company sold certain oil and gas leases, wells and gathering equipment in its Fayetteville Shale play for $518.3 million. The sale included approximately 6% of the Company's net acres in the play as of December 31, 2007. Additionally, the Company has sold, or has agreements to sell, various oil and gas properties in the Gulf Coast and the Permian Basin for approximately $250 million in the aggregate. Approximately $179 million of these proceeds will be received in the third quarter of 2008. Proceeds from the sales of oil and gas properties are credited to the full cost pool when received.

On July 1, 2008, the Company announced that it had closed the previously announced sale of its utility, Arkansas Western Gas Company, to SourceGas, LLC for approximately $230 million, subject to post-closing adjustments. As a result of the sale of the utility, the Company is no longer engaged in any natural gas distribution operations. The Company expects to record a gain on the sale of the utility of approximately $55 million in the third quarter of 2008.

These announced sales represent all of the Company's planned 2008 divestitures and, once all have closed, are expected to result in gross proceeds of approximately $1.0 billion. A portion of the proceeds from these sales has been used to pay down borrowings under the Company's credit facility and the remainder will be used to help fund its 2008 capital investment program.

(17) NEW ACCOUNTING PRONOUNCEMENTS

In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 ("FSP FAS 157-2"). FSP FAS 157-2 delays the effective date of FAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). FSP FAS 157-2 is effective for the Company's fiscal year beginning January 1, 2009. The adoption of FSP FAS 157-2 is not expected to have a material impact on the Company's results of operations and financial condition**.**

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (FAS 161). FAS 161 requires enhanced disclosures for derivative instruments and hedging activities that include explanations of how and why an entity uses derivatives, how instruments and the related hedged items are accounted for under FAS 133 and related interpretations, and how derivative instruments and related hedged items affect the entity's financial position, results of operations and cash flows. FAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company is currently reviewing the standard to assess what impact of the adoption of FAS 161 will have on the Company's results of operations and 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 2007 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three- and six-month periods ended June 30, 2008 and 2007. 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 2007 Annual Report on Form 10-K.

The following discussion 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 "Cautionary Statement About Forward-Looking Statements" in the forepart of this Form 10-Q, in Item 1A, "Risk Factors" in Part I and elsewhere in our 2007 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 consolidated financial statements and the related notes included in this Form 10-Q.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on the exploration and production of natural gas within the United States. Our operations primarily are located in Arkansas, Oklahoma and Texas. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas gathering and marketing businesses, which we refer to collectively as our Midstream Services. We have historically operated principally in three segments: Exploration and Production (E&P), Midstream Services and Natural Gas Distribution. On July 1, 2008, we closed the sale of our utility subsidiary, Arkansas Western Gas Company ("AWG") and, as a result, we no longer have any natural gas distribution operations. The assets and liabilities of AWG have been reclassified as "held for sale" in our June 30, 2008 and December 31, 2007 balance sheets, however, the results of operations for AWG are appropriately consolidated in the statements of operations and are not presented as "discontinued operations." We refer you to Note 4 to the consolidated financial statements included in this Form 10-Q for additional information.

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 June 30, 2008, Compared with Three Months Ended June 30, 2007

In the second quarter of 2008, our gas and oil production increased to 45.1 Bcfe, up 74% from the second quarter of 2007. The 19.2 Bcfe increase in 2008 production was due to an 18.9 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program, with the remainder of the increase coming from our East Texas and Arkoma operations. The average price realized for our gas production, including the effects of hedges, increased approximately 18% to $8.17 per Mcf for the three months ended June 30, 2008, as compared to the same period last year.

We reported net income of $136.6 million in the second quarter of 2008, or $0.39 per share on a fully diluted basis, up 187% from the prior year. Operating income for our E&P segment was $215.1 million for the second quarter of 2008, up $133.7 million, or 164%, from the comparable period of 2007, primarily due to an increase in revenues of $195.9 million from higher gas production volumes and increased product prices, partially offset by an increase in operating costs and expenses of $62.2 million. Operating income for our Midstream Services segment was $15.0 million for the second quarter of 2008, up significantly from $2.3 million in the second quarter of 2007, due to an increase of $19.4 million in gathering revenues and an increase of $1.6 million in the margin generated from our natural gas marketing activities, which were only partially offset by an $8.3 million increase in operating costs and expenses, exclusive of gas purchased costs. The seasonal operating loss for our Natural Gas Distribution segment decreased 50% to $0.9 million for the three months ended June 30, 2008, as the result of a rate increase implemented in August 2007.

We had capital investments of $415.5 million for the second quarter of 2008, of which $362.8 million was invested in our E&P segment, compared to $396.8 million in the second quarter of 2007, of which $369.1 million was invested in our E&P segment.

Six Months Ended June 30, 2008, Compared with Six Months Ended June 30, 2007

For the six months ended June 30, 2008, our gas and oil production increased to 84.1 Bcfe, up 73% compared to the same period in 2007. The 35.4 Bcfe increase in 2008 production was due to a 34.3 Bcf increase in net production from our Fayetteville Shale play with the remainder of the increase coming from our East Texas and Arkoma operations. The average price realized for our gas production, including the effects of hedges, increased approximately 17% to $7.95 per Mcf for the six months ended June 30, 2008, as compared to the same period last year.

We reported net income of $245.6 million for the first six months of 2008, or $0.71 per share on a fully diluted basis, up 149% from the prior year. Operating income for our E&P segment was $380.8 million for the six months ended June 30, 2008, up $225.1 million, or 145%, from the comparable period of 2007, due to an increase in revenues of $346.7 million from higher gas production volumes and increased product prices, partially offset by an increase in operating costs and expenses of $121.5 million. Operating income for our Midstream Services segment was $25.2 million for the first six months of 2008, up significantly from $2.3 million for the same period of 2007, due to an increase of $34.1 million in gathering revenues and an increase of $2.2 million in the margin generated from our natural gas marketing activities, which were only partially offset by a $13.5 million increase in operating costs and expenses, exclusive of gas purchased costs. Operating income for our Natural Gas Distribution segment increased 40% to $10.7 million for the six months ended June 30, 2008, as the result of a rate increase implemented in August 2007.

Our capital investments increased approximately 14% to $825.4 million for the six months ended June 30, 2008, of which $739.3 million was invested in our E&P segment, compared to $724.1 million in the first six months of 2007, of which $670.3 million was invested in our E&P segment.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended June 30,		For the six months ended June 30,	
	2008	2007	2008	2007
Revenues (in thousands)	$ 377,725	$ 181,798	$ 689,742	$ 343,059
Operating income (in thousands)	$ 215,086	$ 81,352	$ 380,796	$ 155,662
Gas production (MMcf)	44,312	24,848	82,517	46,734
Oil production (MBbls)	127	166	269	333
Total production (MMcfe)	45,075	25,841	84,132	48,732
Average gas price per Mcf, including hedges	$ 8.17	$ 6.90	$ 7.95	$ 6.81
Average gas price per Mcf, excluding hedges	$ 10.00	$ 6.83	$ 8.82	$ 6.53
Average oil price per Bbl	$ 122.26	$ 61.72	$ 108.69	$ 58.42
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.95	$ 0.73	$ 0.87	$ 0.73
General & administrative expenses	$ 0.41	$ 0.48	$ 0.42	$ 0.47
Taxes, other than income taxes	$ 0.16	$ 0.21	$ 0.16	$ 0.23
Full cost pool amortization	$ 2.01	$ 2.41	$ 2.15	$ 2.33

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up $195.9 million, or 108%, for the three months ended June 30, 2008, compared to the same period in 2007. Approximately $132.0 million, or 67%, of the increase was attributable to an increase in production volumes and $63.7 million, or 33%, was attributable to higher gas and oil prices realized. E&P revenues were up $346.7 million, or 101%, for the first half of 2008, compared to the first half of 2007, of which approximately $240.1 million, or 69%, of the increase, was attributable to an increase in production volumes and $107.6 million, or 31%, was attributable to higher gas and oil prices realized. We expect our production volumes to continue to increase due to the development of our Fayetteville Shale play in Arkansas. Gas and oil prices are difficult to predict and subject to wide price fluctuations. As of July 25, 2008, we had hedged 60.5 Bcf of our remaining 2008 gas production, 135.0 Bcf of 2009 gas production and 50.0 Bcf of 2010 gas production to limit our exposure to price fluctuations. Revenues for the first six months of 2008 and 2007 also included pre-tax gains of $4.0 million and $5.1 million, respectively, related to the sale of gas in storage inventory. We refer you to Note 7 to the consolidated financial statements included in this Form 10-Q and to “Commodity Prices” below for additional information.

Operating Income. Operating income from our E&P segment was up 164% to $215.1 million for the second quarter of 2008 from $81.4 million for the same period in 2007, as the increase in revenues was partially offset by a 62% increase in operating costs and expenses. For the six months ended June 30, 2008, operating income increased 145% to $380.8 million from $155.7 million for the same period in 2007, as the increase in revenues was partially offset by a 65% increase in operating costs and expenses.

Production. Gas and oil production during the second quarter of 2008 was up approximately 74% to 45.1 Bcfe, due to an 18.9 Bcf increase in net production from our Fayetteville Shale play, as a result of our ongoing development program, and a 0.3 Bcfe increase in our other operating areas. Gas and oil production was up approximately 73% to 84.1 Bcfe for the first six months of 2008, as compared to prior periods, due to a 34.3 Bcf increase in net production from our Fayetteville Shale play and a 1.1 Bcfe increase in our other operating areas. Our total gas production was up approximately 78% to 44.3 Bcf for the second quarter of 2008, which represented approximately 98% of our total equivalent production, and up approximately 77% to 82.5 Bcf for the first six months of 2008. Net production from the Fayetteville Shale was 29.6 Bcf in the second quarter of 2008, compared to 10.7 Bcf in the second quarter of 2007. For the first six months of 2008, net production from the Fayetteville Shale was 53.2 Bcf, compared to 18.9 Bcf for the first six months of 2007. In the second quarter of 2008, we completed the sale of 55,631 net acres, or approximately 6% of our December 31, 2007 total net acres in the Fayetteville Shale play, for $518.3 million. Production from the acreage sold was approximately 10.5 MMcf per day at the time of the sale. Additionally, we have sold, or have agreements to sell, our Gulf Coast and Permian Basin properties. Production from these properties was approximately 1.3 Bcfe in the second quarter of 2008.

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 Notes 7 and 8 to the consolidated financial statements included in this Form 10-Q for additional discussion). The average price realized for our gas production, including the effects of hedges, increased approximately 18% to $8.17 per Mcf for the three months ended June 30, 2008, and increased 17% to $7.95 per Mcf for the six months ended June 30, 2008, as compared to the same periods last year. The change in the average price realized reflects changes in average spot market prices and the effects of our price hedging activities. Our hedging activities decreased the average gas price $1.83 per Mcf during the second quarter of 2008, compared to an increase of $0.07 per Mcf during the second quarter of 2007. Our hedging activities decreased our average gas price $0.87 per Mcf for the first six months of 2008, compared to an increase of $0.28 per Mcf during the same period of 2007. We had protected approximately 76% of our production in the second quarter of 2008, and expect to protect approximately 73% of our anticipated gas production for the remainder of the year 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 six months of 2008 was approximately $0.66 lower than average NYMEX spot prices, which represented the average locational basis differential.

As of July 25, 2008, we have NYMEX commodity price hedges in place for 60.5 Bcf of our remaining 2008 gas production. For our 2009 and 2010 future gas production, we have hedges in place on 135.0 Bcf and 50.0 Bcf, respectively. Additionally, we have basis swaps on 50.4 Bcf for the remainder of 2008, 26.0 Bcf for 2009 and on 7.6 Bcf for 2010, 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 increased 30% to $0.95 for the second quarter of 2008, and increased 19% to $0.87 for the first six months of 2008, both as compared to $0.73 for the same periods in 2007. The increases were driven by the higher per unit operating costs associated with our Fayetteville Shale operations, including the impact that higher natural gas prices had on the cost of compressor fuel. Our Fayetteville Shale production is growing rapidly and is expected to continue to provide upward pressure on our per unit operating costs. We expect our per unit operating cost for this segment to range between $0.92 and $0.97 per Mcfe for 2008.

General and administrative expenses per Mcfe decreased 15% to $0.41 for the second quarter of 2008 and decreased 11% to $0.42 for the first six months of 2008, both as compared to the prior periods of 2007, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $18.4 million in the second quarter of 2008, compared to $12.3 million in the second quarter of 2007, and were $34.9 million for the first six months of 2008, compared to $23.1 million for the first six months of 2007. The increases in general and administrative expenses were primarily due to increases in incentive compensation, and payroll and benefit-costs associated with the expansion of our E&P operations due to the Fayetteville Shale play which accounted for $5.1 million, or 84%, of the second quarter increase and $9.7 million, or 82%, of the six-month increase. Of the remaining increases, increased expenses associated with leased aircraft accounted for 12% of the increase in the second quarter of 2008 and 11% for the first six months of 2008. We expect our cost per unit for general and administrative expenses in 2008 to range between $0.42 and $0.47 per Mcfe.

Our full cost pool amortization rate averaged $2.01 per Mcfe for the second quarter of 2008, as compared to $2.41 per Mcfe for the same period in 2007. For the first six months of 2008, our full cost pool amortization rate averaged $2.15 per Mcfe, compared to $2.33 per Mcfe for the same period in 2007. The declines in the average amortization rates were the result of sales of oil and gas properties in the second quarter of 2008. The proceeds from the sales of approximately $581.1 million were credited to the full cost pool. The amortization rate is impacted by 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, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. Additional proceeds of approximately $179 million will be received in the third quarter of 2008 and will also have the effect of reducing the average full cost pool amortization rate. 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 other factors, including but not limited to the uncertainty of the amount of future reserves attributed to our Fayetteville Shale play. Unevaluated costs excluded from amortization were $415.9 million at June 30, 2008, compared to $221.8 million at June 30, 2007, and $372.4 million at December 31, 2007. The increase in unevaluated costs since June 30, 2007, resulted from an $82.2 million increase in our undeveloped leasehold acreage and seismic costs (with $53.6 million of the increase related to our Fayetteville Shale play) and a $97.2 million increase in our drilling activity.

Taxes other than income taxes per Mcfe decreased to $0.16 for the second quarter of 2008, compared to $0.21 for the same period in 2007 and decreased to $0.16 for the six months ended June 30, 2008, compared to $0.23 for the first six months of 2007. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices. Additionally, we accrued $0.5 million, or $0.01 per Mcfe, and $2.3 million, or $0.03 per Mcfe, in the second quarter and first six months of 2008, respectively, for severance tax refunds related to our East Texas production, compared to accruals for $1.3 million, or $0.05 per Mcfe, and $1.4 million, or $0.03 per Mcfe, in the second quarter and first six months of 2007, respectively. In April 2008, the State of Arkansas enacted legislation that will increase the severance tax on natural gas produced within the state to a base rate of 5%, subject to certain periods of reduced rates for high-cost gas wells, new discovery gas wells and gas wells that produce below a specified level, effective January 1, 2009. Once effective, the new tax rates will increase the severance taxes we pay with respect to all of our production within the State of Arkansas, including our Fayetteville Shale operations, and negatively impact our results of operations.

The timing and amount of production and reserve additions attributed to our Fayetteville Shale play could have a material impact on our per unit costs; if production or reserves additions are lower than projected, our per unit costs could 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 June 30, 2008, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At June 30, 2008, the ceiling value of our reserves was calculated based upon quoted market prices of $13.10 per Mcf for Henry Hub gas and $136.50 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at June 30, 2008 decreased the calculated ceiling value by approximately $475.4 million (net of tax). We had approximately 237.5 Bcf of future gas production hedged at June 30, 2008. Decreases in market prices from June 30, 2008 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 June 30,		For the six months ended June 30,	
	2008	2007	2008	2007
	($ in thousands, except volumes)			
Revenues – marketing	$ 612,884	$ 226,187	$ 998,605	$ 399,838
Revenues – gathering	$ 26,874	$ 7,480	$ 46,478	$ 12,418
Gas purchases – marketing	$ 609,366	$ 224,221	$ 992,426	$ 395,900
Operating costs and expenses	$ 15,390	$ 7,136	$ 27,494	$ 14,035
Operating income	$ 15,002	$ 2,310	$ 25,163	$ 2,321
Gas volumes marketed (Bcf)	59.5	32.3	109.6	59.4
Gas volumes gathered (Bcf)	49.9	15.5	88.4	26.2

Revenues and Operating Income

Revenues. Revenues from our Midstream Services segment were up 174% to $639.8 million in the second quarter of 2008 and up 154% to $1,045.1 million for the first six months of 2008, as compared to the prior year periods. Approximately 92% and 94% of the increases in gathering revenues for the second quarter and first six months of 2008, respectively, resulted from increases in volumes gathered related to the Fayetteville Shale play. The increase in marketing revenues for the second quarter of 2008 resulted from a 27.2 Bcf increase in volumes marketed and a 47% increase in the price received for volumes marketed. The increase in marketing revenues for the first six months of 2008 resulted from a 50.2 Bcf increase in volumes marketed and a 35% increase in the price received for volumes marketed. Increases in volumes marketed were due to the increasing volume of gas produced in the Fayetteville Shale play. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to our Fayetteville Shale play are developed and production increases.

Operating Income. Operating income from our Midstream Services segment increased to $15.0 million in the second quarter of 2008 and to $25.2 million for the first six months of 2008, compared to $2.3 million for both the second quarter and first six months of 2007, as a result of the increases in gathering revenues from the Fayetteville Shale play and increases in the margin generated by gas marketing activities. The margin generated from natural gas marketing activities was $3.5 million for the second quarter of 2008, compared to $2.0 million for the second quarter of 2007 and $6.2 million for the first six months of 2008, compared to $3.9 million for the first six months of 2007. Margins may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increases in volumes marketed in the second quarter and first six months of 2008, as compared to the same periods in 2007, resulted from marketing our increased E&P production volumes and volumes for third parties in areas where we have production. Of the total volumes marketed, production from our E&P operated wells accounted for 99% and 89% in the second quarters of 2008 and 2007, respectively, and 99% and 87% in the six month periods ended June 30, 2008 and 2007, respectively. 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 June 30,		For the six months ended June 30,	
	2008	2007	2008	2007
Revenues (in thousands)	$ 33,519	$ 27,605	$ 117,710	$ 104,599
Gas purchases (in thousands)	$ 20,463	$ 16,186	$ 79,120	$ 70,403
Operating costs and expenses (in thousands)	$ 13,913	$ 13,125	$ 27,857	$ 26,521
Operating income (loss) (in thousands)	$ (857)	$ (1,706)	$ 10,733	$ 7,675
Sales and end-use transportation deliveries (Bcf)	4.3	4.2	14.5	13.7
Sales customers at period-end	150,181	149,272	150,181	149,272
Average sales rate per Mcf	$ 13.69	$ 11.34	$ 11.61	$ 10.85
Heating weather – degree days	391	359	2,588	2,300
Percent of normal	128%	111%	104%	92%

Effective July 1, 2008, we closed the previously announced sale of our utility, AWG, to SourceGas, LLC for approximately $230 million, subject to post-closing adjustments. We expect to recognize a gain on the sale of approximately $55 million in the third quarter of 2008. As a result of the sale of the utility, we are no longer engaged in any natural gas distribution operations. The assets and liabilities of AWG have been reclassified as "held for sale" in our consolidated June 30, 2008 and December 31, 2007 balance sheets, however, the results of operations for AWG are appropriately consolidated in the statements of operations and are not presented as "discontinued operations." We refer you to Note 4 to the consolidated financial statements included in this Form 10-Q for additional information.

Revenues and Operating Income

Revenues increased 21% to $33.5 million for the second quarter of 2008 and increased 13% to $117.7 million for the six months ended June 30, 2008, compared to the prior year periods. Approximately 72% of the increases in revenues resulted from an increase in gas costs and approximately 28% resulted from a rate increase implemented in August 2007. Weather during the first six months of 2008 was 4% colder than normal and 12% colder than the same period in 2007.

The seasonal operating loss in the second quarter of 2008 decreased 50% and operating income for the six months ended June 30, 2008 increased 40%, both as compared to the prior year periods. The decrease in the second quarter 2008 operating loss resulted from the rate increase implemented in August 2007. The increase in operating income for the first six months of 2008 resulted from the rate increase implemented in August 2007.

Deliveries and Rates

Deliveries were up 2% in the second quarter and increased 6% for the six months ended June 30, 2008, as compared to the same periods in 2007, due to the effects of weather. The average sales rate per Mcf increased 21% during the second quarter of 2008 and increased 7% during the first six months of 2008 reflecting the change in natural gas prices and the impact of incremental volumes delivered.

Our utility segment hedged 2.0 Bcf of derivative gas purchases during the first six months of 2008 which had the effect of increasing its total gas supply cost by $1.2 million. In the first six months of 2007, our utility hedged 3.1 Bcf of its gas supply, which increased its total gas supply cost by $6.6 million. See Item 3 and Notes 7 and 8 to the consolidated financial statements included in this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Operating Costs and Expenses

For the first half of 2008, operating costs and expenses (exclusive of purchased gas costs) for this segment were slightly higher than the comparable period of the prior year due to increased payroll and other operating costs.

Other Revenues

Other revenues for the first six months of 2008 and 2007 included pre-tax gains of $4.0 million and $5.1 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, increased to $9.0 million and $20.5 million for the second quarter and first six months of 2008, respectively, compared to $5.0 million and $6.5 million for the same periods of 2007. The increases were due to increased debt levels resulting from our increased level of capital investments, partially offset by increased capitalized interest. We capitalized interest of $7.3 million in the second quarter and $13.5 million in the first six months of 2008, compared to $2.9 million and $6.0 million, respectively, for the same periods in 2007, as our costs excluded from amortization in the E&P segment have continued to increase along with the overall increased level of our capital investments. Our costs excluded from amortization were $415.9 million at June 30, 2008, up from $221.8 million at June 30, 2007.

Income Taxes

Our provision for income taxes was an effective rate of 38.0% for both the first six months of 2008 and 2007. Any changes in the provision for income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences. As a result of the gains from the sales of Fayetteville Shale acreage, the utility and certain oil and gas properties, we expect to be subject to future alternative minimum tax payments during 2008.

Pension Expense

We incurred pension costs of $1.9 million and $3.8 million in the second quarter and first six months of 2008, respectively, for our pension and other postretirement benefit plans, compared to $1.3 million and $2.6 million for the same periods of 2007. The increases were 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. As a result of the sale of the natural gas distribution segment on July 1, 2008, we expect that the pension expense for the remainder of 2008 could be decreased by approximately 40% due to the transfer of employees to the acquiring entity. We currently expect to contribute $8.5 million to our pension and other postretirement plans in 2008. As of June 30, 2008, $3.6 million has been contributed to the pension plans and $0.2 million has been contributed to the postretirement benefit plans. For further information regarding our pension plans, we refer you to Note 13 to the consolidated financial statements included in this Form 10-Q.

Stock-Based Compensation

We recognized expense of $1.5 million and capitalized $0.9 million to the full cost pool for stock-based compensation in the second quarter of 2008, compared to $1.1 million expensed and $0.5 million capitalized to the full cost pool for the comparable period of 2007. For the first six months of 2008, we recognized expense of $3.2 million and capitalized $1.8 million to the full cost pool for stock-based compensation, compared to $2.6 million expensed and $1.2 million capitalized to the full cost pool for the first six months of 2007. We refer you to Note 12 to the consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

Adoption of Accounting Principles

During the first quarter of 2008, we partially adopted Statement of Financial Accounting Standards 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. This statement applies to other accounting pronouncements that require or permit fair value measurements, and is effective for financial statements issued for fiscal years beginning after November 15, 2007. In addition to required disclosures, FAS 157 also requires companies to evaluate current measurement techniques. The adoption of FAS 157 had no material impact on our results of operations and financial condition. See Note 8 to the consolidated financial statements included in this Form 10-Q for further information.

During the first quarter of 2008, we adopted Statement of Financial Accounting Standards 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 and 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 adoption of FAS 159 had no impact on our results of operations and financial condition.

In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 ("FSP FAS 157-2"). FSP FAS 157-2 delays the effective date of FAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). FSP FAS 157-2 is effective for our fiscal year beginning January 1, 2009. Items deferred by FSP FAS 157-2 are not expected to have a material impact on our results of operations and financial condition**.**

In March 2008, the Financial Accounting Standards Board issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133" (FAS 161). FAS 161 requires enhanced disclosures for derivative instruments and hedging activities that include explanations of how and why an entity uses derivatives, how these instruments and the related hedged items are accounted for under FAS 133 and related interpretations, and how derivative instruments and related hedged items affect the entity's financial position, results of operations and cash flows. FAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently reviewing the standard to assess what impact the adoption of FAS 161 would have on our results of operations and financial condition.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our unsecured revolving credit facility (discussed below under "Financing Requirements") and funds accessed through 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 June 30, 2008, we had no indebtedness outstanding under our revolving credit facility and at December 31, 2007, we had $842.2 million outstanding under our revolving credit facility.

On January 16, 2008, we completed a private placement of $600 million of 7.5% Senior Notes due 2018 (discussed below under "Financing Requirements"). Net proceeds of approximately $591 million from the offering were used to pay outstanding indebtedness under our revolving credit facility.

In the second quarter of 2008, we completed the sale of 55,631 net acres, or approximately 6% of our total net acres in the Fayetteville Shale play, for approximately $518.3 million. Production from the acreage sold was approximately 10.5 MMcf per day at the time of the sale.

Net cash provided by operating activities increased 128% to $588.3 million in the first six months of 2008, compared to $258.2 million for the same period in 2007, due to a $282.8 million increase in net income and adjustments for non-cash expenses. During the first six months of 2008, requirements for our capital investments were funded from our revolving credit facility, cash generated by operating activities and the net proceeds from the Fayetteville Shale acreage sale.

Effective July 1, 2008, we closed the previously announced sale of our utility, AWG, to SourceGas, LLC for approximately $230 million, subject to post-closing adjustments. We expect to recognize a gain on the sale of approximately $55 million in the third quarter of 2008. As a result of the sale of the utility, we are no longer engaged in natural gas distribution operations. Additionally, we have sold, or have agreements to sell, various oil and gas properties in the Gulf Coast and the Permian Basin for approximately $250 million in the aggregate. Approximately $179 million of these proceeds will be received in the third quarter of 2008. Proceeds from the sales of oil and gas properties are credited to the full cost pool. These announced sales represent all of our planned 2008 divestitures and, once all have closed, are expected to result in gross proceeds of approximately $1.0 billion. After-tax proceeds from these sales will be invested in short-term cash equivalents. A portion of the proceeds from these sales has been used to pay down borrowings under our credit facility and the remainder will be used to help fund our capital investment programs.

At June 30, 2008, our capital structure consisted of 33% debt and 67% equity. We believe that our operating cash flow and the proceeds from the sales of the Fayetteville Shale acreage, oil and gas leases in the Permian Basin, our utility and other E&P asset divestitures we expect to close in the third quarter of 2008 will be adequate to meet our capital and operating requirements for 2008.

Our cash flow from operating activities is highly dependent upon the 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 Notes 7 and 8 to the consolidated 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 available cash flow.

Capital Investments

Our capital investments increased to $825.4 million for the first six months of 2008, compared to $724.1 million for the same period last year. Our E&P segment investments were $739.3 million during the first six months of 2008 and were $670.3 million for the comparable period in 2007. Our capital investments for 2008 are currently expected to be approximately $1.7 billion, consisting of $1.54 billion for E&P, $135 million for Midstream Services and $25 million for general corporate purposes. We expect to allocate approximately $1.15 billion of our 2008 E&P capital to our Fayetteville Shale play. Although the remainder of our 2008 capital investment program is expected to be funded through cash flow from operations and after-tax proceeds from the sales of E&P assets and utility assets as discussed above, we may adjust the level of 2008 capital investments dependent upon the level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $736.0 million at June 30, 2008, compared to $978.8 million at December 31, 2007. 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 our agreement with our existing or additional lenders. As of June 30, 2008, we had no indebtedness outstanding under our revolving credit facility compared to $842.2 million outstanding as of December 31, 2007. As discussed more fully below, in January 2008, we issued $600 million of 7.5% Senior Notes due 2018, the net proceeds of which were used to repay amounts outstanding under our revolving credit facility. The interest rate on the credit 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, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services Company (SES) 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. Any future downgrades in our public debt ratings could increase our cost of funds under the credit facility.

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 June 30, 2008. 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 may have to decrease our capital investment plans.

On January 16, 2008, we issued $600 million of 7.5% Senior Notes due 2018 in a private placement, which are rated BB+ by Standard and Poor’s and Ba2 by Moody’s. The 7.5% Senior Notes are redeemable at our election, in whole or in part, at any time at a redemption price equal to the greater of: (1) 100% of the principal amount of the notes to be redeemed then outstanding; and (2) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the redemption date on a semiannual basis as determined in accordance with the indenture, plus 50 basis points, plus, in either of such cases, accrued and unpaid interest to the date of redemption on the notes to be redeemed. In addition, if we undergo a “change of control,” as defined in the indenture, holders of the 7.5% Senior Notes will have the option to require us to purchase all or any portion of the notes at a purchase price equal to 101% of the principal amount of the notes to be purchased plus any accrued and unpaid interest to, but excluding, the change of control date. Payment obligations with respect to the 7.5% Senior Notes are currently guaranteed by our subsidiaries, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services Company (SES), which guarantees may be unconditionally released in certain circumstances. As a result of the issuance of the guarantees of the 7.5% Senior Notes, and in order for all of our senior notes to rank equally, on May 2, 2008, we and our subsidiaries, SEECO, SEPCO and SES, entered into supplemental indenture agreements with the trustees under the indentures relating to our 7.625% Medium-Term Notes due 2027, 7.125% Fixed Rate Notes due October 10, 2017, 7.35% Fixed Rate Notes due October 2, 2017 and 7.15% Notes due 2018, pursuant to which SEECO, SEPCO and SES became guarantors of such notes to the same extent to which such subsidiaries have guaranteed our 7.5% Senior Notes. We refer you to Note 6, "Condensed Consolidating Financial Information" in this Form 10-Q for additional information. The indentures governing our senior notes contain covenants that, among other things, restrict our ability and/or our subsidiaries to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets.

At June 30, 2008, our capital structure consisted of 33% debt and 67% equity. Our capital structure at June 30, 2008 would have been 28% debt and 72% equity without consideration of accumulated other comprehensive losses in shareholders’ equity related to our commodity hedge position and our pension liability. Our total debt is expected to decline to 25% to 30% of our capital structure by year end, primarily due to our operating results and to the approximately $1.0 billion of pre-tax cash proceeds received or expected to be received from our asset sales. Stockholders’ equity at June 30, 2008, includes an accumulated other comprehensive loss of $451.2 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 $10.9 million related to changes in our pension liability. The amount recorded for FAS 133 is based on current market values of our hedges at June 30, 2008, 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.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 65% of our expected 2008 gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital investments.

Our 7.625% Senior Notes due 2027 are putable by the note holders on May 1, 2009, and as a result, the $60 million principal balance of these notes has been reclassified to short-term debt in our balance sheet. If the put option is exercised in 2009, we anticipate cash would be available to pay the notes, or alternatively, we would borrow the required funds under our revolving credit facility.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. On January 16, 2008, we issued $600 million of 7.5% Senior Notes due 2018 in a private placement. In the first quarter of 2008, we exercised the first of our three options to increase the volumes to be transported on each of the two pipeline laterals and related facilities being constructed by Texas Gas Transmission, LLC for which we are the anchor shipper, and subsequent to the second quarter, we exercised our remaining options. Once effective, which can occur no earlier than April 1, 2010, the exercised options will result in aggregate commitments of 800,000 MMBtu per day on the Fayetteville Lateral and 640,000 MMBtu per day on the Greenville Lateral. Other than the issuance of the notes and the increase in pipeline volume commitments, there have been no material changes to our contractual obligations from those disclosed in our 2007 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Based on actuarial data, giving effect to the sale of AWG, we expect to record expenses of approximately $6.1 million in 2008 for these plans, of which $3.8 million has been recorded in the first six months of 2008. At June 30, 2008, we recognized a liability of $13.9 million as a result of the underfunded status of our pension and other postretirement benefit plans, compared to a liability of $14.6 million at December 31, 2007. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 13 to the 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, at which time management may reserve amounts that are reasonably estimable.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described above. We had negative working capital of $363.5 million at June 30, 2008, and $67.6 million at December 31, 2007. Current assets increased $442.7 million at June 30, 2008, compared to current assets at December 31, 2007, due to a $176.0 million increase in cash equivalents from proceeds received from the sale of certain oil and gas leases, a $173.8 million increase in our current deferred income tax benefit related to our hedging activities and a $129.1 million increase in accounts receivable. Current liabilities increased $738.6 million as a result of an increase of $510.7 million in our current hedging liability, a $114.6 million increase in accounts payable, a $60.0 million increase due to the reclassification of our 7.625% Senior Notes due 2027 that are putable at the holders' option in 2009 as a current liability and a $51.9 million increase in current income taxes payable related to the sales of assets. Changes related to hedging activities reflect a significant increase in commodity prices for natural gas at June 30, 2008.

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 8.2 Bcf at $3.79 per Mcf at June 30, 2008, compared to 10.1 Bcf at $4.05 per Mcf at December 31, 2007.

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

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 our customers and their dispersion across geographic areas. No single customer accounted for greater than 7% of accounts receivable at June 30, 2008. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At June 30, 2008, we had $736.0 million of total debt with an average interest rate of 7.48% and we had no indebtedness outstanding under our revolving credit 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 deemed 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 and 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 relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are periodically reviewed to 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 gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At June 30, 2008, the fair value of our financial instruments related to natural gas production was a $740.5 million liability.

	Volume	Weighted Average Price to be Swapped ($)	Weighted Average Price ($)	Weighted Average Ceiling Price ($)	Weighted Average Basis Differential ($)	Fair value at June 30, 2008 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2008[1]	37.0	8.38	—	—	—	(186.4)
2009[2]	76.1	8.30	—	—	—	(285.7)
2010	28.0	8.76	—	—	—	(62.8)
Costless Collars:						
2008	23.5	—	7.60	10.68	—	(76.5)
2009	59.0	—	8.71	11.69	—	(130.6)
2010	14.0	—	8.29	10.57	—	(23.2)
Basis Swaps:						
2008	47.4	—	—	—	(0.47)	22.9
2009	26.0	—	—	—	(0.55)	1.9
2010	7.6	—	—	—	(0.63)	(3.8)
Matched-Basis Swaps:						
2008	3.0	—	—	—	(0.71)	3.7

(1) Includes fixed-price swaps for 50,000 Mcf relating to future sales from our underground storage facility that have a fair value liability of approximately $41,000.

(2) Includes fixed-price swaps for 0.1 Bcf relating to future sales from our underground storage facility that have a fair value liability of $0.1 million.

At June 30, 2008, we had outstanding fixed-price basis differential swaps on 47.4 Bcf of 2008, 26.0 Bcf of 2009 and 7.6 Bcf of 2010 gas production that did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gas and oil sales. For the six months ended June 30, 2008, we recorded an unrealized gain of $21.7 million related to the differential swaps that did not qualify for hedge accounting treatment and a $42.4 million loss related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

At December 31, 2007, we had outstanding natural gas price swaps on total notional volumes of 55.7 Bcf in 2008 and 56.0 Bcf in 2009 for which we will receive fixed prices ranging from $7.29 to $9.98 per MMBtu. At December 31, 2007, we had outstanding fixed price basis differential swaps on 8.0 Bcf of 2008 gas production that qualified for hedge treatment and outstanding fixed price basis differential swaps on 66.8 Bcf of 2008 and 2009 gas production that did not qualify for hedge treatment.

At December 31, 2007, we had collars in place on notional volumes of 48.0 Bcf in 2008 and 23.0 Bcf in 2009. The 48.0 Bcf in 2008 had an average floor and ceiling price of $7.92 and $11.60 per MMBtu, respectively. The 23.0 Bcf in 2009 had an average floor and ceiling price of $8.09 and $10.91 per MMBtu, respectively.

Midstream Services

At June 30, 2008, our Midstream Services segment had outstanding fair value hedges in place on 1.5 Bcf and 0.5 Bcf of gas for 2008 and 2009, respectively. These hedges are a mixture of fixed-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from July 2008 through March 2009 and have a net fair value liability of $5.5 million as of June 30, 2008.

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 level of 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 June 30, 2008, which included providing 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 June 30, 2008 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 2007 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.

The Company held its Annual Meeting of Shareholders on May 6, 2008, for the purpose of electing Directors of the Company for the ensuing year and to ratify the appointment of PricewaterhouseCoopers LLP to serve as the Company's independent registered public accounting firm for 2008. Holders of 311,312,595 shares (91.04% of total outstanding shares) voted in total.

The Directors were elected with the number of shares voted as follows:

	Voted For	Withheld
Lewis E. Epley, Jr.	309,485,612	1,826,983
Robert L. Howard	306,145,914	5,166,681
Harold M. Korell	306,314,511	4,998,084
Vello A. Kuuskraa	309,634,577	1,678,018
Kenneth R. Mourton	306,211,033	5,101,562
Charles E. Scharlau	289,929,030	21,383,565

Holders of 310,863,689 shares voted for the proposal to ratify the appointment of PricewaterhouseCoopers LLP to serve as the Company's independent registered public accounting firm for 2008, 167,974 shares voted against and 280,932 shares abstained.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(4.1) Second Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and The Bank of New York Trust Company, N.A., as trustee, dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008)

(4.2) Third Supplemental Indenture by and among Southwestern Energy Company, SEECO, Inc., Southwestern Energy Production Company, Southwestern Energy Services Company and UMB Bank, N.A., as trustee, dated as of May 2, 2008. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed on May 8, 2008)

(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: July 30, 2008

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