UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **September 30, 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 Parkway 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☒ 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 ☒ 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 ☒

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 October 24, 2008
Common Stock, Par Value $0.01	343,327,466

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);
- our ability to transport our production to the most favorable markets or at all;
- 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, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties, 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 the 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 September 30, 2008	For the three months ended September 30, 2007	For the nine months ended September 30, 2008	For the nine months ended September 30, 2007
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 431,019	$ 201,095	$ 1,160,569	$ 596,798
Gas marketing	229,568	81,361	574,866	208,916
Oil sales	9,565	10,113	38,816	29,566
Gas gathering	12,662	3,438	30,134	6,281
Transportation and other	185	1,615	7,090	10,795
	682,999	297,622	1,811,475	852,356
Operating Costs and Expenses:				
Gas purchases – midstream services	225,149	78,588	560,490	201,293
Gas purchases – gas distribution	—	2,063	61,439	57,471
Operating expenses	23,877	21,562	77,903	62,084
General and administrative expenses	21,055	20,099	70,536	54,782
Depreciation, depletion and amortization	105,230	81,426	300,478	203,646
Taxes, other than income taxes	8,648	4,431	24,793	17,862
	383,959	208,169	1,095,639	597,138
Operating Income	299,040	89,453	715,836	255,218
Interest Expense:				
Interest on long-term debt	14,205	10,695	46,950	22,204
Other interest charges	482	173	1,749	1,099
Interest capitalized	(8,109)	(3,604)	(21,595)	(9,575)
	6,578	7,264	27,104	13,728
Other Income (Loss)	2,354	83	2,530	(21)
Gain on Sale of Utility Assets	57,264	—	57,264	—
Income Before Income Taxes and Minority Interest	352,080	82,272	748,526	241,469
Minority Interest in Partnership	(197)	(79)	(547)	(273)
Income Before Income Taxes	351,883	82,193	747,979	241,196
Provision for Income Taxes:				
Current	61,000	—	107,500	—
Deferred	72,715	31,233	176,732	91,654
	133,715	31,233	284,232	91,654
Net Income	$ 218,168	$ 50,960	$ 463,747	$ 149,542
Earnings Per Share:				
Basic	$ 0.64	$ 0.15 (1)	$ 1.36	$ 0.44 (1)
Diluted	$ 0.63	$ 0.15 (1)	$ 1.34	$ 0.43 (1)
Weighted Average Common Shares Outstanding:				
Basic	342,312,845	339,591,040 (1)	341,595,957	338,584,608 (1)
Diluted	346,712,565	345,088,224 (1)	346,459,853	344,726,838 (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

	September 30, 2008	December 31, 2007
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 426,188	$ 727
Accounts receivable	254,129	177,680
Inventories, at average cost	48,364	33,034
Hedging asset – FAS 133	136,286	64,472
Current assets held for sale (see Note 4)	—	58,877
Other	24,650	28,551
Total current assets	889,617	363,341
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $498.1 million in 2008 and $372.4 million in 2007 excluded from amortization	4,426,177	4,020,448
Gathering systems	291,512	158,604
Gas in underground storage	13,349	13,349
Other	113,052	85,983
	4,844,090	4,278,384
Less: Accumulated depreciation, depletion and amortization	1,499,632	1,200,754
	3,344,458	3,077,630
Assets Held For Sale (see Note 4)	—	143,234
Other Assets	129,931	38,511
Total Assets	$ 4,364,006	$ 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

	September 30, 2008	December 31, 2007
	(in thousands)	
Current Liabilities		
Short-term debt	$ 61,200	$ 1,200
Accounts payable	440,526	313,070
Taxes payable	78,930	5,087
Interest payable	12,119	2,213
Advances from partners	56,617	32,005
Hedging liability – FAS 133	27,596	8,598
Current deferred income taxes	47,902	20,909
Current liabilities associated with assets held for sale (see Note 4)	—	39,118
Other	7,955	8,695
Total current liabilities	732,845	430,895
Long-Term Debt	674,800	977,600
Other Liabilities		
Deferred income taxes	635,604	479,196
Long-term hedging liability	49,467	15,186
Pension liability	5,546	12,268
Liabilities associated with assets held for sale (see Note 4)	—	15,417
Other	34,384	35,084
	725,001	557,151
Commitments and Contingencies		
Minority Interest in Partnership	10,608	10,570
Stockholders' Equity		
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 343,182,556 shares in 2008 and 341,581,672 in 2007(1)	3,432	3,416
Additional paid-in capital(1)	807,019	752,369
Retained earnings	1,345,778	882,031
Accumulated other comprehensive income	69,255	13,348
Common stock in treasury, 224,807 shares in 2008 and 222,774 in 2007(1)	(4,732)	(4,664)
	2,220,752	1,646,500
Total Liabilities and Stockholders' Equity	$ 4,364,006	$ 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 nine months ended September 30, 2008	For the nine months ended September 30, 2007
	(in thousands)	
Cash Flows From Operating Activities		
Net Income	$ 463,747	$ 149,542
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	301,801	204,662
Deferred income taxes	176,732	91,654
Gain on sale of utility assets	(57,264)	—
Unrealized gain on derivatives	(5,956)	(2,669)
Stock-based compensation expense	5,379	3,839
Gain on sale of property, plant and equipment	(392)	—
Minority interest in partnership	39	(122)
Change in assets and liabilities:		
Accounts receivable	(59,690)	(4,683)
Inventories	(32,397)	(12,756)
Accounts payable	115,184	21,513
Taxes payable	67,834	(3,797)
Interest payable	9,784	3,055
Advances from partners and customer deposits	24,432	5,501
Deferred tax benefit – stock options	(42,197)	(17,858)
Other assets and liabilities	(329)	(2,863)
Net cash provided by operating activities	966,707	435,018
Cash Flows From Investing Activities		
Capital investments	(1,287,324)	(1,139,946)
Proceeds from sale of property, plant and equipment	732,924	5,777
Net proceeds from sale of utility assets	213,721	—
Other items	(816)	383
Net cash used in investing activities	(341,495)	(1,133,786)
Cash Flows From Financing Activities		
Debt retirement	(600)	(600)
Payments on revolving long-term debt	(1,843,600)	(628,050)
Borrowings under revolving long-term debt	1,001,400	1,222,350
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	42,197	17,858
Change in bank drafts outstanding	5,402	42,013
Proceeds from exercise of common stock options	3,240	4,160
Net cash provided by (used in) financing activities	(200,856)	656,456
Increase (decrease) in cash and cash equivalents	424,356	(42,312)
Cash and cash equivalents at beginning of year	1,832 (1)	42,927
Cash and cash equivalents at end of period	$ 426,188	$ 615

(1) Cash and cash equivalents for 2008 at the beginning of the year 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	—	—	—	463,747	—	—	463,747
Change in value of derivatives	—	—	—	—	50,338	—	50,338
Change in value of pension and other postretirement liabilities	—	—	—	—	5,569	—	5,569
Total comprehensive income (loss)							519,654
Tax benefit for stock-based compensation	—	—	42,197	—	—	—	42,197
Stock-based compensation – FAS 123(R)	—	—	9,147	—	—	—	9,147
Exercise of stock options	1,557	16	3,224	—	—	—	3,240
Issuance of restricted stock	106	1	(1)	—	—	—	—
Cancellation of restricted stock	(62)	(1)	1	—	—	—	—
Issuance of stock awards	4	—	82	—	—	—	82
Treasury stock – non-qualified plan	—	—	—	—	—	(68)	(68)
Balance at September 30, 2008	343,183	$ 3,432	$ 807,019	$ 1,345,778	$ 69,255	$ (4,732)	$ 2,220,752

(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 September 30, 2008	For the three months ended September 30, 2007	For the nine months ended September 30, 2008	For the nine months ended September 30, 2007
		(in thousands)		
Net Income	$ 218,168	$ 50,960	$ 463,747	$ 149,542
Change in value of derivatives				
Current period reclassification to earnings	32,129	(16,136)	67,775	(30,075)
Current period ineffectiveness	(19,748)	(870)	6,533	3,939
Current period change in derivative instruments	513,785	39,782	(23,970)	28,966
Total change in value of derivatives	526,166	22,776	50,338	2,830
Change in value of pension and other postretirement liabilities				
Sale of utility – divestiture, curtailment and settlement	9,040	—	9,040	—
Current period change in value of pension and other postretirement liabilities	(3,890)	435	(3,471)	435
Total change in value of pension and other postretirement liabilities	5,150	435	5,569	435
Comprehensive income (loss), end of period	$ 749,484	$ 74,171	$ 519,654	$ 152,807

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
September 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.

Cash and cash equivalents are defined by the Company as short-term, highly liquid investments that have an original maturity of three months or less and deposits in money market mutual funds that are readily convertible into cash. Management considers cash and cash equivalents to have minimal credit and market risk.

(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 September 30, 2008 and 2007, the Company's unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At September 30, 2008, the ceiling value of the Company's reserves was calculated based upon quoted market prices of $7.12 per Mcf for Henry Hub gas and $97.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at

September 30, 2008, increased the calculated ceiling value by approximately $230.2 million (net of tax). The Company had approximately 213.5 Bcf of future gas production hedged at September 30, 2008. Decreases in market prices from September 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 nine months ended September 30, 2008 and 2007, respectively. For the periods ended September 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 September 30,		For the nine months ended September 30,	
	2008	2007	2008	2007
Net Income (in thousands)	$ 218,168	$ 50,960	$ 463,747	$ 149,542
Number of Common Shares:				
Weighted average outstanding	342,312,845	339,591,040	341,595,957	338,584,608
Issued upon assumed exercise of outstanding stock options	3,971,851	5,013,094	4,445,642	5,694,574
Effect of issuance of nonvested restricted common shares	427,869	484,090	418,254	447,656
Weighted average and potential dilutive outstanding[(1)]	346,712,565	345,088,224	346,459,853	344,726,838
Net Income per Common Share:				
Basic	$ 0.64	$ 0.15	$ 1.36	$ 0.44
Diluted	$ 0.63	$ 0.15	$ 1.34	$ 0.43

(1) Options for 349,410 shares for the nine months ended September 30, 2008 and 452,946 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, 40,597 shares of restricted stock for the nine months ended September 30, 2008 and 800 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. The Company received $223.5 million (net of expenses related to the sale) and, in order to receive regulatory approval for the sale and certain related transactions, paid $9.8 million to AWG for the benefit of its customers. The Company recorded a pre-tax gain on the sale of $57.3 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 December 31, 2007 balance sheet.

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

	December 31, 2007
	(in thousands)
Current Assets:	
Cash	$ 1,105
Accounts receivable	29,826
Inventory	23,737
Hedging asset – FAS 133	2,387
Other current assets	1,822
	$ 58,877
Long-term assets, including property, plant and equipment, net of accumulated depreciation and amortization	$ 143,234
Current Liabilities:	
Accounts payable	$ 3,700
Interest payable	171
Taxes payable	7,547
Deferred gas purchases	16,289
Customer deposits	7,551
Hedging liability – FAS 133	2,387
Other current liabilities	1,473
	$ 39,118
Long-term Liabilities:	
Deferred income taxes	$ 15,066
Other long-term liabilities	351
	$ 15,417

(5) DEBT

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

	September 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.

The Company has an unsecured revolving credit facility with a borrowing capacity of $1.0 billion which 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 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 September 30, 2008, the Company's capital structure consisted of 25% debt and 75% 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 of such debt. 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.

In November 2007, the Company entered an agreement to sell AWG, a non-guarantor subsidiary, and the sale was consummated as of July 1, 2008. The assets and liabilities of AWG have been presented as "held for sale" in the condensed consolidating balance sheet for the non-guarantor subsidiaries as of December 31, 2007.

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 September 30, 2008:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$ 669,394	$ 34,930	$ (21,325)	$ 682,999
Operating costs and expenses:					
Gas purchases	—	225,972	—	(823)	225,149
Operating expenses	—	32,834	11,433	(20,390)	23,877
General and administrative expenses	—	18,029	3,138	(112)	21,055
Depreciation, depletion and amortization	—	101,762	3,468	—	105,230
Taxes, other than income taxes	—	7,785	863	—	8,648
Total operating costs and expenses	—	386,382	18,902	(21,325)	383,959
Operating income	—	283,012	16,028	—	299,040
Other income (loss)	57,264	2,336	18	—	59,618
Equity in earnings of subsidiaries	182,664	—	—	(182,664)	—
Interest expense	—	3,118	3,460	—	6,578
Income before income taxes and minority interest	239,928	282,230	12,586	(182,664)	352,080
Minority interest in partnership	—	(197)	—	—	(197)
Provision for income taxes	21,760	107,172	4,783	—	133,715
Net income	$ 218,168	$ 174,861	$ 7,803	$ (182,664)	$ 218,168

Three months ended September 30, 2007:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$ 284,993	$ 29,825	$ (17,196)	$ 297,622
Operating costs and expenses:					
Gas purchases	—	83,546	7,555	(10,450)	80,651
Operating expenses	—	16,291	11,877	(6,606)	21,562
General and administrative expenses	—	14,317	5,922	(140)	20,099
Depreciation, depletion and amortization	—	77,992	3,434	—	81,426
Taxes, other than income taxes	—	3,317	1,114	—	4,431
Total operating costs and expenses	—	195,463	29,902	(17,196)	208,169
Operating income	—	89,530	(77)	—	89,453
Other income (loss)	—	36	47	—	83
Equity in earnings of subsidiaries	50,960	—	—	(50,960)	—
Interest expense	—	5,444	1,820	—	7,264
Income before income taxes and minority interest	50,960	84,122	(1,850)	(50,960)	82,272
Minority interest in partnership	—	(79)	—	—	(79)
Provision (benefit) for income taxes	—	31,938	(705)	—	31,233
Net income	$ 50,960	$ 52,105	$ (1,145)	$ (50,960)	$ 50,960

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS (Continued)
(Unaudited)

Nine months ended September 30, 2008:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$1,697,039	$ 205,755	$ (91,319)	$1,811,475
Operating costs and expenses:					
Gas purchases	—	585,748	79,120	(42,939)	621,929
Operating expenses	—	83,130	42,752	(47,979)	77,903
General and administrative expenses	—	55,144	15,793	(401)	70,536
Depreciation, depletion and amortization	—	288,531	11,947	—	300,478
Taxes, other than income taxes	—	20,925	3,868	—	24,793
Total operating costs and expenses	—	1,033,478	153,480	(91,319)	1,095,639
Operating income	—	663,561	52,275	—	715,836
Other income (loss)	57,264	2,777	(247)	—	59,794
Equity in earnings of subsidiaries	428,243	—	—	(428,243)	—
Interest expense	—	15,983	11,121	—	27,104
Income before income taxes and minority interest	485,507	650,355	40,907	(428,243)	748,526
Minority interest in partnership	—	(547)	—	—	(547)
Provision for income taxes	21,760	246,927	15,545	—	284,232
Net income	$ 463,747	$ 402,881	$ 25,362	$ (428,243)	$ 463,747

Nine months ended September 30, 2007:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Operating revenues	$ —	$ 758,745	$ 151,456	$ (57,845)	$ 852,356
Operating costs and expenses:					
Gas purchases	—	222,800	77,959	(41,995)	258,764
Operating expenses	—	42,450	35,056	(15,422)	62,084
General and administrative expenses	—	38,441	16,769	(428)	54,782
Depreciation, depletion and amortization	—	194,368	9,278	—	203,646
Taxes, other than income taxes	—	14,567	3,295	—	17,862
Total operating costs and expenses	—	512,626	142,357	(57,845)	597,138
Operating income	—	246,119	9,099	—	255,218
Other income (loss)	—	130	(151)	—	(21)
Equity in earnings of subsidiaries	149,542	—	—	(149,542)	—
Interest expense	—	9,049	4,679	—	13,728
Income before income taxes and minority interest	149,542	237,200	4,269	(149,542)	241,469
Minority interest in partnership	—	(273)	—	—	(273)
Provision for income taxes	—	90,034	1,620	—	91,654
Net income	$ 149,542	$ 146,893	$ 2,649	$ (149,542)	$ 149,542

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

September 30, 2008:	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
ASSETS					
Cash and cash equivalents	$ 452,234	$ (26,735)	$ 689	$ —	$ 426,188
Accounts receivable	883	250,038	3,208	—	254,129
Inventories, at average cost	—	47,600	764	—	48,364
Other	5,544	155,118	274	—	160,936
Total current assets	458,661	426,021	4,935	—	889,617
Intercompany receivables	1,031,236	(781,207)	(242,156)	(7,873)	—
Investments	—	9,371	(9,370)	(1)	—
Property, plant and equipment, at cost	52,580	4,463,175	328,335	—	4,844,090
Accumulated depreciation, depletion and amortization	(28,342)	(1,434,106)	(37,184)	—	(1,499,632)
Net property, plant and equipment	24,238	3,029,069	291,151	—	3,344,458
Investments in subsidiaries (equity method)	1,524,601	—	—	(1,524,601)	—
Other assets	15,023	81,417	33,491	—	129,931
Total assets	$ 3,053,759	$ 2,764,671	$ 78,051	$ (1,532,475)	$4,364,006
LIABILITIES AND STOCKHOLDERS' EQUITY					
Accounts and notes payable	$ 258,847	$ 326,555	$ 15,247	$ (7,874)	$ 592,775
Other current liabilities	1,611	136,981	1,478	—	140,070
Total current liabilities	260,458	463,536	16,725	(7,874)	732,845
Long-term debt	674,800	—	—	—	674,800
Other liabilities	18,958	65,185	5,254	—	89,397
Commitments and contingencies					
Deferred income taxes	(121,209)	747,791	9,022	—	635,604
Minority interest in partnership	—	10,608	—	—	10,608
Total liabilities	833,007	1,287,120	31,001	(7,874)	2,143,254
Stockholders' equity	2,220,752	1,477,551	47,050	(1,524,601)	2,220,752
Total liabilities and stockholders' equity	$ 3,053,759	$ 2,764,671	$ 78,051	$ (1,532,475)	$4,364,006

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)

Nine months ended September 30, 2008:	Parent	Guarantors	Non-Guarantors (in thousands)	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (42,785)	$ 974,474	$ 35,018	$ —	$ 966,707
Investing activities:					
Capital investments	(5,001)	(1,133,008)	(149,315)	—	(1,287,324)
Proceeds from sale of property, plant and equipment	213,721	684,494	48,430	—	946,645
Other items	4,570	3,087	(8,473)	—	(816)
Net cash provided by (used in) investing activities	213,290	(445,427)	(109,358)	—	(341,495)
Financing activities:					
Intercompany activities	452,160	(547,621)	148,675	(53,214)	—
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	42,197	—	—	—	42,197
Other items	19,533	1,445	(75,045)	53,214	(853)
Net cash provided by (used in) financing activities	271,690	(546,176)	73,630	—	(200,856)
Increase (decrease) in cash and cash equivalents	442,195	(17,129)	(710)	—	424,356
Cash and cash equivalents at beginning of year	10,040	(9,607)	1,399 (1)	—	1,832
Cash and cash equivalents at end of period	$ 452,235	$ (26,736)	$ 689	$ —	$ 426,188

Nine months ended September 30, 2007:	Parent	Guarantors	Non-Guarantors (in thousands)	Eliminations	Consolidated
Net cash provided by operating activities	$ 8,267	$ 400,452	$ 26,299	$ —	$ 435,018
Investing activities:					
Capital investments	(5,928)	(1,041,623)	(92,395)	—	(1,139,946)
Proceeds from sale of property, plant and equipment	—	5,777	—	—	5,777
Other items	3,178	(5,992)	3,197	—	383
Net cash used in investing activities	(2,750)	(1,041,838)	(89,198)	—	(1,133,786)
Financing activities:					
Intercompany activities	(691,007)	627,286	63,721	—	—
Payments on revolving long-term debt	(628,050)	—	—	—	(628,050)
Borrowings under revolving long-term debt	1,222,350	—	—	—	1,222,350
Excess tax benefit for stock-based compensation	17,858	—	—	—	17,858
Other items	44,298	1,168	(1,168)	—	44,298
Net cash provided by (used in) financing activities	(34,551)	628,454	62,553	—	656,456
Decrease in cash and cash equivalents	(29,034)	(12,932)	(346)	—	(42,312)
Cash and cash equivalents at beginning of year	46,951	(4,424)	400	—	42,927
Cash and cash equivalents at end of period	$ 17,917	$ (17,356)	$ 54	$ —	$ 615

(1) Cash and cash equivalents for 2008 at the beginning of the year 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. The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy entities at the time the transactions are entered into and continually monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the recent events in the financial markets demonstrate there can be no assurance that a counterparty financial institution will be able to meet its obligations to the Company. The Company has not incurred any credit-related losses in 2008 associated with its derivative activities and believes that its counterparties will continue to be able to meet their obligations under these transactions.

At September 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 September 30, 2008, the Company's net asset recorded on the balance sheet related to its hedging activities was \$134.8 million. Additionally, at September 30, 2008, the Company recorded a gain to other comprehensive income of \$75.0 million related to its hedging activities net of a deferred income tax liability of \$41.3 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 September 30, 2008 remain unchanged, the Company would expect to transfer an aggregate after-tax gain of approximately \$58.3 million from accumulated other comprehensive income to earnings during the next 12 months. The change in accumulated other comprehensive income related to derivatives was a gain of \$848.7 million (\$526.2 million after tax) compared to a gain of \$36.2 million (\$22.8 million after tax) for the three months ended September 30, 2008 and 2007, respectively, and a gain of \$81.2 million (\$50.3 million after tax) compared to a gain of \$4.5 million (\$2.8 million after tax) for the nine months ended September 30, 2008 and 2007, respectively. The Company recorded increases of \$26.3 million and \$6.0 million in gas sales revenues during the third quarter and first nine months 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 increases of \$7.3 million and \$2.7 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. Pursuant to 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:

	September 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	$ —	$ 53,509	$ 127,429	$ 180,938
Derivative liabilities	—	(11,206)	(34,898)	(46,104)
Total	$ —	$ 42,303	$ 92,531	$ 134,834

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 third quarter and first nine months 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 September 30, 2008.

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

	Net Derivatives (in thousands)
Balance at July 1, 2008	$ (205,202)
Total gains or losses (realized/unrealized):	
Included in earnings[(1)]	11,133
Included in other comprehensive income (loss)	290,117
Purchases, issuances, and settlements	(3,517)
Transfers into/out of Level 3	—
Balance at September 30, 2008	$ 92,531
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of September 30, 2008	$ 7,616

Total Gains and Losses for the nine months ended September 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)]	25,117
Included in other comprehensive income (loss)	49,531
Purchases, issuances, and settlements	(14,884)
Transfers into/out of Level 3	—
Balance at September 30, 2008	$ 92,531
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of September 30, 2008	$ 10,233

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

(9) SEGMENT INFORMATION

The Company's reportable business segments 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. As a result of the closing of the sale of AWG on July 1, 2008, 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, interest and other income (loss), gain on sale of utility assets 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 September 30, 2008:					
Revenues from external customers	$ 440,648	$ 242,229	$ —	$ 122	$ 682,999
Intersegment revenues	17,525	440,942	—	112	458,579
Operating income	280,607	18,254	—	179	299,040
Interest and other income (loss)[1]	2,357	—	—	(3)	2,354
Gain on sale of utility assets	—	—	—	57,264	57,264
Depreciation, depletion and amortization expense	102,015	3,179	—	36	105,230
Interest expense[1]	4,026	2,552	—	—	6,578
Provision for income taxes[1]	105,921	5,966	—	21,828	133,715
Assets	3,374,462	482,138	—	507,406 [2]	4,364,006
Capital investments[3]	415,690	54,222	—	1,709	471,621
Three months ended September 30, 2007:					
Revenues from external customers	$ 195,569	$ 84,819	$ 17,234	$ —	$ 297,622
Intersegment revenues	8,561	154,208	20	112	162,901
Operating income (loss)	88,856	4,078	(3,541)	60	89,453
Interest and other income (loss)[1]	299	—	(216)	—	83
Depreciation, depletion and amortization expense	78,279	1,505	1,610	32	81,426
Interest expense[1]	5,483	608	1,173	—	7,264
Provision (benefit) for income taxes[1]	31,766	1,318	(1,873)	22	31,233
Assets	2,838,405	203,649	179,988	71,087 [2]	3,293,129
Capital investments[3]	381,099	31,115	2,498	1,888	416,600
Nine months ended September 30, 2008:					
Revenues from external customers	$ 1,091,005	$ 605,391	$ 114,957	$ 122	$ 1,811,475
Intersegment revenues	56,910	1,122,863	2,753	336	1,182,862
Operating income	661,403	43,417	10,733	283	715,836
Interest and other income (loss)[1]	2,798	—	(270)	2	2,530
Gain on sale of utility assets	—	—	—	57,264	57,264
Depreciation, depletion and amortization expense	289,352	7,586	3,431	109	300,478
Interest expense[1]	17,603	7,184	2,317	—	27,104
Provision for income taxes[1]	245,499	13,768	3,095	21,870	284,232
Assets	3,374,462	482,138	—	507,406 [2]	4,364,006
Capital investments[3]	1,155,025	133,545	3,574	4,877	1,297,021
Nine months ended September 30, 2007:					
Revenues from external customers	$ 515,458	$ 215,217	$ 121,681	$ —	$ 852,356
Intersegment revenues	31,731	436,066	172	336	468,305
Operating income	244,518	6,399	4,134	167	255,218
Interest and other income (loss)[1]	392	—	(420)	7	(21)
Depreciation, depletion and amortization expense	195,392	3,291	4,859	104	203,646
Interest expense[1]	9,122	989	3,617	—	13,728
Provision for income taxes[1]	89,496	2,055	37	66	91,654
Assets	2,838,405	203,649	179,988	71,087 [2]	3,293,129
Capital investments[3]	1,051,422	76,395	8,441	4,436	1,140,694

(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 represent corporate assets not allocated to segments and assets, including investments in cash equivalents, for non-reportable segments.
(3) Capital investments include a reduction of $3.0 million and an increase of $7.0 million for the three- and nine-month periods ended September 30, 2008, respectively, and reductions of $20.2 million and $2.5 million for the three- and nine-month periods ended September 30, 2007, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $407.0 million and $133.7 million for the third quarters of 2008 and 2007, respectively, and $1,035.1 million and $382.8 million for the nine months ended September 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 cash and cash equivalents, furniture and fixtures, 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 nine months ended September 30, 2008	2007
	(in thousands)	
Interest payments	$ 37,044	$ 19,141
Income tax payments	$ 46,500	$ —

As a result of the gains on the proceeds received from the E&P asset sales and the sale of the utility, 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’s subsidiary, Southwestern Energy Services Company (SES) 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 (Texas Gas) for which SES is the anchor shipper, and in the third quarter of 2008, SES 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. In the third quarter of 2008, SES entered into firm transportation agreements with Texas Gas relating to the commitments for the Fayetteville and Greenville Laterals and, in connection therewith, the Company delivered a guaranty of SES’s obligations under the firm transportation agreements to Texas Gas. The Company’s payment obligations under the guaranty are limited to the lesser of (i) 25% of SES’s negotiated demand charges for the full term of the agreement(s), less any payments made by the Company pursuant to the guaranty, or (ii) 25% of SES's negotiated demand charges for the remaining initial terms of the agreement(s) as of the first day of the month of services under the agreements for which payment is claimed, which amount shall reflect any reductions in SES's obligations under the agreements.

On September 30, 2008, SES entered into a precedent agreement pursuant to which it will contract for firm gas transportation services on a proposed new pipeline of Fayetteville Express Pipeline LLC (FEP), which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. SES will be a "Foundation Shipper" for the project and will use the new pipeline primarily to deliver gas volumes produced from the Company's operations in the Fayetteville Shale play in central Arkansas to eastern markets. Pending regulatory approvals, the pipeline is expected to be in-service by late 2010 or early 2011. The proposed pipeline will have an estimated ultimate capacity of up to 2.0 Bcf per day. Following the approval of the pipeline by the Federal Energy Regulatory Commission (FERC) and subject to certain conditions, pursuant to the precedent agreement, SES will enter into a firm transportation agreement to transport up to 1,200,000 Dekatherms per day for an initial term of ten years. In connection with the precedent agreement, the Company delivered to FEP a guaranty of SES's obligations under the precedent agreement and the firm transportation agreements to be entered into thereunder. Initially, and during any period in which SES meets the creditworthiness requirements of the precedent agreement, the Company's payment obligations under the guaranty are zero but will increase upon the occurrence of certain events. Other than the addition of or increase in pipeline volume commitments and the related guaranties, 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 third quarter and first nine months of 2008, the Company recorded compensation cost of $0.8 million and $2.3 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.5 million and $1.0 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 $0.4 million related to stock options for the nine months ended September 30, 2008, compared to a deferred tax benefit of $0.7 million for the comparable period in 2007. A total of $4.9 million of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods. For the third quarter and first nine months of 2007, the Company recorded compensation cost of $0.6 million and $1.9 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.2 million and $0.5 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and were capitalized into the full cost pool.

For the third quarter and first nine months of 2008, the Company recorded compensation cost of $1.0 million and $2.7 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $0.9 million and $2.2 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and were capitalized into the full cost pool. As of September 30, 2008, there was $12.5 million of total unrecognized compensation cost related to nonvested shares of restricted stock. For the third quarter and first nine months of 2007, the Company recorded compensation cost of $0.6 million and $1.9 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $0.5 million and $1.4 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and were capitalized into the full cost pool. Amounts recorded in the third quarter of 2008 for stock options and restricted stock include amounts related to the resignation of one of the Company's executive vice presidents.

The following tables summarize stock option activity for the first nine months of 2008 and provide information for options outstanding at September 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	65,800	37.22
Exercised	(1,557,048)	2.08
Forfeited or expired	(60,761)	24.72
Outstanding at September 30, 2008	7,000,865	$ 5.55
Exercisable at September 30, 2008	6,219,102	$ 3.19

During the first nine months of 2008, there were 65,800 options granted, compared to no options granted during the first nine months of 2007. The total intrinsic value of options exercised during the first nine months of 2008 and 2007 was $57.4 million and $52.1 million, respectively. Associated with the exercise of stock options, the Company recorded a tax benefit of $42.2 million in the first nine months of 2008, compared to $17.9 million in the first nine 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 September 30, 2008	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at September 30, 2008	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$0.75 - $1.00	2,042,464	$ 0.92	2.1		2,042,464	$ 0.92	
$1.01 - $2.50	1,941,238	1.38	3.6		1,941,238	1.38	
$2.51 - $6.00	1,189,180	2.76	4.9		1,189,180	2.76	
$6.01 - $17.75	972,137	10.40	3.3		860,738	9.46	
$17.76 - $44.34	855,846	24.46	5.5		185,482	20.84	
	7,000,865	$ 5.55	3.6	$ 174,922	6,219,102	$ 3.19	$ 170,088

The following table summarizes restricted stock activity for the first nine months 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	106,370	41.68
Vested	(72,781)	12.19
Forfeited	(62,876)	26.05
Unvested shares at September 30, 2008	761,743	$ 23.16

(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 nine-month periods ended September 30, 2008 and 2007:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Service cost	$ 1,033	$ 995	$ 3,849	$ 2,987
Interest cost	695	1,061	3,113	3,182
Expected return on plan assets	(692)	(1,140)	(3,201)	(3,419)
Amortization of prior service cost	84	119	328	356
Amortization of net loss	40	115	389	345
Net periodic benefit cost	$ 1,160	$ 1,150	$ 4,478	$ 3,451

	Postretirement Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2008	2007	2008	2007
	(in thousands)			
Service cost	$ 126	$ 104	$ 456	$ 313
Interest cost	31	54	186	162
Expected return on plan assets	—	(21)	(48)	(61)
Amortization of transition obligation	15	22	59	65
Amortization of prior service cost	2	—	8	—
Amortization of net loss	—	6	34	16
Net periodic benefit cost	$ 174	$ 165	$ 695	$ 495

As a result of the sale of AWG on July 1, 2008, the Company transferred pension and other postretirement plan assets and liabilities related to the employees of AWG to the purchaser. As a result of this transfer, the Company’s net periodic benefit costs for its pension and other postretirement plans are expected to be approximately 30% lower in the second half of 2008, compared to the first half of 2008.

The Company currently expects to contribute $8.1 million to the pension plans and $0.2 million to the postretirement benefit plans in 2008. As of September 30, 2008, $7.3 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 September 30, 2008, 224,807 shares were accounted for as treasury stock, compared to 222,774 shares at December 31, 2007.

(14) INVENTORY

Inventory recorded in current assets includes $26.0 million at September 30, 2008, and $25.0 million at December 31, 2007, for gas in underground storage owned by the Company's E&P segment, and $22.3 million at September 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 $21.6 million at December 31, 2007, that was classified in the balance sheets as "Current Assets Held for Sale."

Other assets includes $33.5 million at September 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.

(15) DIVESTITURES

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 various oil and gas properties in the Gulf Coast and the Permian Basin for approximately $240 million in the aggregate, with approximately $21 million expected to be collected in the fourth quarter of 2008. All proceeds from the sales of oil and gas properties are credited to the full cost pool when received unless the gain or loss on the transaction would significantly alter the relationship between capitalized costs and proved reserves. None of these divestitures significantly altered the relationship between capitalized costs and proved reserves.

In November 2007, the Company entered into an agreement to sell all of the capital stock of AWG for $224 million plus working capital. On July 1, 2008, the transaction was closed. The Company received $223.5 million (net of expenses related to the sale) and, in order to receive regulatory approval for the sale and certain related transactions, paid $9.8 million to AWG for the benefit if its customers. The Company recorded a pre-tax gain on the sale of the utility of $57.3 million in the third quarter of 2008. As a result of the sale of the utility, the Company is no longer engaged in any natural gas distribution operations.

These announced sales represent all of the Company's planned 2008 divestitures and 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.

(16) 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.

In October 2008, the FASB issued FASB Staff Position FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active" (FSP FAS 157-3). FSP FAS 157-3 clarifies the application of FAS 157, "Fair Value Measurements," when a market for that financial asset is inactive. FSP FAS 157-3 became effective for financial statements upon issuance and its adoption did not have a material impact 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 nine-month periods ended September 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 December 31, 2007 balance sheet, 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 our ability to increase our natural gas production and the level of natural gas prices. 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 prices we realize for our production are affected by our hedging activities as well as locational differences in market prices. We are subject to credit risk relating 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 closely monitored to limit our credit risk exposure. We have not incurred any losses to date in 2008 related to non-performance and do not anticipate any losses given the information we have currently. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future. Our ability to increase our natural gas production is dependent upon our ability to economically find and produce natural gas, our ability to control costs and our ability to market natural gas on economically attractive terms to our customers.

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

In the third quarter of 2008, our gas and oil production increased to 52.8 Bcfe, up 76% from the third quarter of 2007. The 22.9 Bcfe increase in 2008 production was due to a 22.5 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 29% to $8.56 per Mcf for the three months ended September 30, 2008, as compared to the same period last year.

We reported net income of $218.2 million in the third quarter of 2008, or $0.63 per share on a fully diluted basis, up 328% from the prior year. Net income for the third quarter of 2008 includes a $35.5 million net of tax gain, or $0.10 per diluted share, related to the sale of our Natural Gas Distribution segment that closed July 1, 2008. Operating income for our E&P segment was $280.6 million for the third quarter of 2008, up $191.8 million, or 216%, from the comparable period of 2007, primarily due to an increase in revenues of $254.0 million from higher gas production volumes and increased product prices, partially offset by an increase in operating costs and expenses of $62.3 million. Operating income for our Midstream Services segment was $18.3 million for the third quarter of 2008, up from $4.1 million in the third quarter of 2007, due to an increase of $23.4 million in gathering revenues and an increase of $1.3 million in the margin generated from our natural gas marketing activities, which were only partially offset by a $10.5 million increase in operating costs and expenses, exclusive of gas purchased costs.

We had capital investments of $471.6 million for the third quarter of 2008, of which $415.7 million was invested in our E&P segment, compared to $416.6 million in the third quarter of 2007, of which $381.1 million was invested in our E&P segment.

Nine Months Ended September 30, 2008, Compared with Nine Months Ended September 30, 2007

For the nine months ended September 30, 2008, our gas and oil production increased to 137.0 Bcfe, up 74% compared to the same period in 2007. The 58.3 Bcfe increase in 2008 production was due to a 56.8 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 21% to $8.19 per Mcf for the nine months ended September 30, 2008, as compared to the same period last year.

We reported net income of $463.7 million for the first nine months of 2008, or $1.34 per share on a fully diluted basis, up 210% from the prior year. Net income for the first nine months of 2008 includes a $35.5 million net of tax gain, or $0.10 per diluted share, related to the sale of our Natural Gas Distribution segment that closed July 1, 2008. Operating income for our E&P segment was $661.4 million for the nine months ended September 30, 2008, up $416.9 million, or 170%, from the comparable period of 2007, due to an increase in revenues of $600.7 million from higher gas production volumes and increased product prices, partially offset by an increase in operating costs and expenses of $183.8 million. Operating income for our Midstream Services segment was $43.4

million for the first nine months of 2008, up from $6.4 million for the same period of 2007, due to an increase of $57.5 million in gathering revenues and an increase of $3.5 million in the margin generated from our natural gas marketing activities, which were only partially offset by a $23.9 million increase in operating costs and expenses, exclusive of gas purchased costs. The Natural Gas Distribution segment provided $10.7 million of operating income in 2008 prior to the sale of this segment on July 1, compared to $4.1 million for the first nine months of 2007.

Our capital investments increased approximately 14% to $1,297.0 million for the nine months ended September 30, 2008, of which $1,155.0 million was invested in our E&P segment, compared to $1,140.7 million in the first nine months of 2007, of which $1,051.4 million was invested in our E&P segment.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended September 30, 2008	For the three months ended September 30, 2007	For the nine months ended September 30, 2008	For the nine months ended September 30, 2007
Revenues (in thousands)	$ 458,173	$ 204,130	$1,147,915	$ 547,189
Operating income (in thousands)	$ 280,607	$ 88,856	$ 661,403	$ 244,518
Gas production (MMcf)	52,375	29,145	134,892	75,879
Oil production (MBbls)	76	139	345	472
Total production (MMcfe)	52,832	29,982	136,964	78,714
Average gas price per Mcf, including hedges	$ 8.56	$ 6.66	$ 8.19	$ 6.75
Average gas price per Mcf, excluding hedges	$ 8.82	$ 5.49	$ 8.83	$ 6.13
Average oil price per Bbl	$ 125.33	$ 72.52	$ 112.37	$ 62.58
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.96	$ 0.67	$ 0.90	$ 0.71
General & administrative expenses	$ 0.33	$ 0.46	$ 0.38	$ 0.47
Taxes, other than income taxes	$ 0.15	$ 0.11	$ 0.15	$ 0.19
Full cost pool amortization	$ 1.86	$ 2.56	$ 2.03	$ 2.41

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up $254.0 million, or 124%, for the three months ended September 30, 2008, compared to the same period in 2007. Approximately $150.1 million, or 59%, of the increase was attributable to an increase in production volumes and $103.9 million, or 41%, was attributable to higher gas and oil prices realized. E&P revenues were up $600.7 million, or 110%, for the first nine months of 2008, compared to the first nine months of 2007, of which approximately $390.6 million, or 65%, of the increase, was attributable to an increase in production volumes and $211.0 million, or 35%, 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 October 24, 2008, we had hedged 28.5 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. 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. Revenues for the first nine 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.

Operating Income. Operating income from our E&P segment was up 216% to $280.6 million for the third quarter of 2008 from $88.9 million for the same period in 2007, as the 124% increase in revenues was partially offset by a 54% increase in operating costs and expenses. For the nine months ended September 30, 2008, operating income increased 170% to $661.4 million from $244.5 million for the same period in 2007, as the 110% increase in revenues was partially offset by a 61% increase in operating costs and expenses.

Production. Gas and oil production during the third quarter of 2008 was up approximately 76% to 52.8 Bcfe, due to a 22.5 Bcf increase in net production from our Fayetteville Shale play, as a result of our ongoing development program, and a 0.4 Bcfe increase in our other operating areas. Gas and oil production was up approximately 74% to 137.0 Bcfe for the first nine months of 2008, as compared to prior periods, due to a 56.8 Bcf increase in net production from our Fayetteville Shale play and a 1.5 Bcfe increase in our other operating areas. Our total gas production was up approximately 80% to 52.4 Bcf for the third quarter of 2008, which represented approximately 99% of our total equivalent production, and up approximately 78% to 134.9 Bcf for the first nine months of 2008. Net production from the Fayetteville Shale was 37.2 Bcf in the third quarter of 2008, compared to 14.7 Bcf in the third quarter of 2007. For the first nine months of 2008, net production from the Fayetteville Shale was 90.4 Bcf, compared to 33.6 Bcf for the first nine 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 sold our Gulf Coast and Permian Basin properties in the second and third quarters of 2008. Production from these properties contributed approximately 0.5 Bcfe and 3.1 Bcfe to total production in the third quarter and nine months ended September 30, 2008, respectively.

We increased our production guidance for the fourth quarter of 2008 to 53.0 to 55.0 Bcfe, up from 50.0 to 52.0 Bcfe, and our guidance for 2008 oil and gas production is now 190.0 to 192.0 Bcfe. Of this total for 2008, approximately 127.0 to 130.0 Bcf is expected to come from the Fayetteville Shale. Our fourth quarter production guidance includes the effect of our oil and gas property sales and our anticipated restrictions on Fayetteville Shale production due to the delay in the completion of the Fayetteville Lateral portion of the Texas Gas Transmission Pipeline (Boardwalk). The Fayetteville Lateral, which was originally anticipated to be in-service in the third quarter of 2008, is now expected to be completed late in the fourth quarter.

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 29% to $8.56 per Mcf for the three months ended September 30, 2008, and increased 21% to $8.19 per Mcf for the nine months ended September 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 $0.26 per Mcf during the third quarter of 2008, compared to an increase of $1.17 per Mcf during the third quarter of 2007. Our hedging activities decreased our average gas price $0.64 per Mcf for the first nine months of 2008, compared to an increase of $0.62 per Mcf during the same period of 2007. We had hedged approximately 75% of our production in the third quarter of 2008 from the impact of widening basis differentials through our hedging activities and sales arrangements. Additionally, as of October 24, 2008, we have basis protected on approximately 43.0 Bcf of our fourth quarter 2008 expected gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX gas prices of approximately $0.90 to $1.00 per Mcf. Disregarding the impact of hedges, the average price received for our gas production during the first nine months of 2008 was approximately $0.90 lower than average NYMEX spot prices, which represented the average locational basis differential.

As of October 24, 2008, we had NYMEX fixed price hedges in place on notional volumes of 11.5 Bcf of our fourth quarter 2008 gas production at an average price of $8.39 per MMBtu and collars in place on notional volumes of 17.0 Bcf of our fourth quarter 2008 gas production at an average floor and ceiling price of $7.76 and $10.70 per MMBtu, respectively. Late in the third quarter of 2008, locational basis differentials on Centerpoint East began widening above historical averages as a result of the delay in the construction of the Boardwalk Pipeline. The continued delay of the pipeline could further adversely impact locational differentials for production from the Arkoma Basin.

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 30.9 Bcf for the remainder of 2008, 26.0 Bcf for 2009, 10.1 Bcf for 2010 and on 1.8 Bcf for 2011, in order to reduce the effects of widening market differentials on prices we receive.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment increased 43% to $0.96 for the third quarter of 2008, and increased 27% to $0.90 for the first nine months of 2008, both as compared to 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 the fourth quarter of 2008.

General and administrative expenses per Mcfe decreased 28% to $0.33 for the third quarter of 2008 and decreased 19% to $0.38 for the first nine 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 $17.2 million in the third quarter of 2008, compared to $13.7 million in the third quarter of 2007, and were $52.1 million for the first nine months of 2008, compared to $36.8 million for the first nine months of 2007. The increases in general and administrative expenses were primarily due to increases in payroll, incentive compensation and employee-related costs associated with the expansion of our E&P operations due to the Fayetteville Shale play. These increases accounted for $2.2 million, or 63%, of the third quarter increase and $11.9 million, or 78%, of the nine-month increase. Payroll and incentive compensation expenses in the third quarter of 2008 also included costs related to the resignation of an executive officer of the Company and a negative $2.2 million related to the decrease in valuation of Company stock held in our non-qualified plan. Of the remaining increase in third quarter general and administrative expenses, increases in information technology related expenses and disaster-relief donations accounted for 13% and 8%, respectively, of the increase. Of the remaining increase in general and administrative expenses for the first nine months of 2008, increased expenses associated with leased aircraft accounted for 9% of the increase and increased information technology related expenses accounted for 5% of the increase. We expect our cost per unit for general and administrative expenses in the fourth quarter of 2008 to range between $0.32 and $0.37 per Mcfe.

Our full cost pool amortization rate averaged $1.86 per Mcfe for the third quarter of 2008, as compared to $2.56 per Mcfe for the same period in 2007. For the first nine months of 2008, our full cost pool amortization rate averaged $2.03 per Mcfe, compared to $2.41 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 and third quarters of 2008, as the proceeds from these sales 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. 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 $498.1 million at September 30, 2008, compared to $288.8 million at September 30, 2007, and $372.4 million at December 31, 2007. The increase in unevaluated costs since September 30, 2007, resulted primarily from a $38.9 million increase in our undeveloped leasehold acreage and seismic costs (with $8.4 million of the increase related to our Fayetteville Shale play) and a $151.1 million increase in our drilling activity.

Taxes other than income taxes per Mcfe increased to $0.15 for the third quarter of 2008, compared to $0.11 for the same period in 2007 and decreased to $0.15 for the nine months ended September 30, 2008, compared to $0.19 for the first nine 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 $2.2 million, or $0.04 per Mcfe, and $4.5 million, or $0.03 per Mcfe, in the third quarter and first nine months of 2008, respectively, for severance tax refunds related to our East Texas production, compared to refund accruals for $2.0 million, or $0.07 per Mcfe, and $3.3 million, or $0.04 per Mcfe, in the third quarter and first nine 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 September 30, 2008, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At September 30, 2008, the ceiling value of our reserves was calculated based upon quoted market prices of $7.12 per Mcf for Henry Hub gas and $97.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at September 30, 2008 increased the calculated ceiling value by approximately $230.2 million (net of tax). We had approximately 213.5 Bcf of future gas production hedged at September 30, 2008. Decreases in market prices from September 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 September 30,		For the nine months ended September 30,	
	2008	2007	2008	2007
	($ in thousands, except volumes)			
Revenues – marketing	$ 649,521	$ 228,771	$ 1,648,126	$ 628,609
Revenues – gathering	$ 33,650	$ 10,256	$ 80,128	$ 22,674
Gas purchases – marketing	$ 645,701	$ 226,209	$ 1,638,127	$ 622,109
Operating costs and expenses	$ 19,216	$ 8,740	$ 46,710	$ 22,775
Operating income	$ 18,254	$ 4,078	$ 43,417	$ 6,399
Gas volumes marketed (Bcf)	71.6	40.2	181.2	99.5
Gas volumes gathered (Bcf)	64.6	22.3	153.0	48.5

Revenues and Operating Income

Revenues. Revenues from our Midstream Services segment were up 186% to $683.2 million in the third quarter of 2008 and up 165% to $1,728.3 million for the first nine months of 2008, as compared to the prior year periods. Approximately 91% and 93% of the increases in gathering revenues for the third quarter and first nine months of 2008, respectively, resulted from increases in volumes gathered related to the Fayetteville Shale play. The increase in marketing revenues for the third quarter of 2008 resulted from a 31.4 Bcf increase in volumes marketed and a 59% increase in the price received for volumes marketed. The increase in marketing revenues for the first nine months of 2008 resulted from an 81.7 Bcf increase in volumes marketed largely resulting from increased production from the Fayetteville Shale play and a 44% increase in the price received for volumes marketed. Of the total volumes marketed, production from our E&P operated wells accounted for 96% and 89% in the third quarters of 2008 and 2007, respectively, and 95% and 87% in the nine-month periods ended September 30, 2008 and 2007, respectively. 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 $18.3 million in the third quarter of 2008 and to $43.4 million for the first nine months of 2008, compared to $4.1 million for the third quarter of 2007 and $6.4 million for the first nine 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 $3.8 million for the third quarter of 2008, compared to $2.6 million for the third quarter of 2007 and $10.0 million for the first nine months of 2008, compared to $6.5 million for the first nine 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 third quarter and first nine months of 2008, as compared to the same periods in 2007, resulted from marketing our increased E&P production volumes as well as volumes for third parties in areas where we have production. 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

In November 2007, we 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. We received $223.5 million (net of expenses related to the sale) and, in order to receive regulatory approval for the sale and certain related transactions, paid $9.8 million to AWG for the benefit of its customers. We recorded a pre-tax gain on the sale of $57.3 million in the third quarter of 2008. As a result of the sale of AWG, we no longer have any natural gas distribution operations. AWG provided operating income for 2008 of $10.7 million prior to the sale, compared to $4.1 million for the first nine months of 2007.

Other Revenues

Other revenues for the first nine 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, decreased to $6.6 million for the third quarter of 2008, compared to $7.3 million for the third quarter of 2007. The decrease was due to increased capitalized interest, partially offset by interest expense incurred on our increased debt levels resulting from our increased level of capital investments. Interest costs, net of capitalization increased to $27.1 million for the first nine months of 2008, compared to $13.7 million for the same period of 2007. The increase was due to increased debt levels resulting from our increased level of capital investments, partially offset by increased capitalized interest. We capitalized interest of $8.1 million in the third quarter and $21.6 million in the first nine months of 2008, compared to $3.6

million and $9.6 million for the same periods in 2007, respectively, 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 $498.1 million at September 30, 2008, up from $288.8 million at September 30, 2007.

Interest income for the third quarter and nine months ended September 30, 2008 was $2.3 million and $2.6 million, respectively. Interest income earned on our cash equivalents is recorded in other income on the Statements of Operations.

Income Taxes

Our provision for income taxes was an effective rate of 38.0% for both the first nine 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 E&P asset sales and the sale of the utility, we expect to be subject to future alternative minimum tax payments during 2008.

Pension Expense

We incurred pension costs of $1.3 million and $5.2 million in the third quarter and first nine months of 2008, respectively, for our pension and other postretirement benefit plans, compared to $1.3 million and $3.9 million for the same periods of 2007. As a result of the sale of AWG, we transferred pension and other postretirement plan assets and liabilities related to the employees of AWG to the purchaser. Accordingly, our net periodic benefit costs for our pension and other postretirement plans are expected to be approximately 30% lower in the second half of 2008, compared to the first half of 2008.

The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $8.1 million to our pension plans and $0.2 million to our other postretirement benefit plans in 2008. As of September 30, 2008, $7.3 million has been contributed to the pension plans and $0.2 million has been contributed to the postretirement benefit plans. The recent events in the financial markets may require changes in management's assumptions relative to expected return on plan assets which could, in turn, adversely impact the funded status of our pension plans and increase the amount of future contribution requirements. 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 $1.8 million and capitalized $1.4 million to the full cost pool for stock-based compensation in the third quarter of 2008, compared to $1.2 million expensed and $0.7 million capitalized to the full cost pool for the comparable period of 2007. For the first nine months of 2008, we recognized expense of $5.0 million and capitalized $3.2 million to the full cost pool for stock-based compensation, compared to $3.8 million expensed and $1.9 million capitalized to the full cost pool for the first nine months of 2007. Amounts recorded in the third quarter of 2008 for stock-based compensation include amounts related to the resignation of an executive officer. 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 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 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.

In October 2008, the FASB issued FASB Staff Position FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active" (FSP FAS 157-3). FSP FAS 157-3 clarifies the application of FAS 157, "Fair Value Measurements," when a market for that financial asset is inactive. FSP FAS 157-3 became effective for financial statements upon issuance and its adoption did not have a material impact on the Company's 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 September 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. Effective July 1, 2008, we closed the previously announced sale of our utility, AWG, to SourceGas, LLC. We received $223.5 million (net of expenses related to the sale) and, in order to receive regulatory approval for the sale and certain related transactions, paid $9.8 million to AWG for the benefit of its customers. We recorded a pre-tax gain on the sale of $57.3 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 various oil and gas properties in the Gulf Coast and the Permian Basin for approximately $240 million in the aggregate, with approximately $21 million expected to be collected in the fourth quarter of 2008. Proceeds from the sales of these 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. 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. Until required, the additional proceeds from these sales are invested in short-term cash equivalents.

Net cash provided by operating activities increased 122% to $966.7 million in the first nine months of 2008, compared to $435.0 million for the same period in 2007, due to a $437.2 million increase in net income and adjustments for non-cash expenses. During the first nine 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 our previously announced asset sales.

At September 30, 2008, our capital structure consisted of 25% debt and 75% equity, and we had available $426.2 million in cash and cash equivalents. We believe that our operating cash flow, the proceeds from our divestitures and available funds under our revolving credit facility will be adequate to meet our capital and operating requirements for 2008 and 2009. The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the facility. While we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet its obligation under the facility.

Current economic conditions make it very difficult to access debt and equity markets for funding. Given the unused capacity on our revolving credit facility and our expectations of cash flow from our future operations, we do not plan on accessing those markets in the near term. Our cash flow from operating activities is highly dependent upon the market prices that we receive for our gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors which are impacted by the overall state of the economy. 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. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependant on the timely collection of receivables from our customers and partners. We actively manage this risk through credit management activities and through the date of this filing have not experienced any significant delays in collections. However, sustained inaccessibility of credit by our customers and partners, as is currently being experienced, could adversely impact our cash flows.

In the current global economic environment, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow.

Capital Investments

Our capital investments increased to $1.3 billion for the first nine months of 2008, compared to $1.14 billion for the same period last year. Our E&P segment investments were $1,155.0 million during the first nine months of 2008 and were $1,051.4 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 September 30, 2008, compared to $978.8 million at December 31, 2007. Our unsecured revolving credit facility has a borrowing capacity of $1.0 billion, which may be increased to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of September 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 are rated BB+ by Standard and Poor's and we have a Corporate Family Rating of Ba2 by Moody's. Any 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 September 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 SEECO, SEPCO and 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 September 30, 2008, our capital structure consisted of 25% debt and 75% equity, and we had available $426.2 million in cash and cash equivalents. Our debt as a percentage of total capital has declined throughout 2008, primarily due to our operating results and to the proceeds received from our asset sales. Stockholders' equity at September 30, 2008, includes an accumulated other comprehensive gain of $75.0 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 $5.7 million related to changes in our pension and other postretirement liabilities. The amount recorded for FAS 133 is based on current market values of our hedges at September 30, 2008, and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our credit facility's financial covenants with respect to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 and FAS 158 and the non-cash impact of any full cost ceiling write-downs. Our capital structure at September 30, 2008 would have remained 25% debt and 75% equity without consideration of accumulated other comprehensive income (loss) in stockholders' equity related to our commodity hedge position and our pension and other postretirement liabilities.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged 28.5 Bcf of our expected fourth quarter 2008 gas production, and 135.0 Bcf of our expected 2009 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, SES 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 SES is the anchor shipper, and in the third quarter of 2008, SES 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. In the third quarter of 2008, SES entered into firm transportation agreements with Texas Gas relating to the commitments for the Fayetteville and Greenville Laterals and, in connection therewith, we delivered a guaranty of SES's obligations under the firm transportation agreements to Texas Gas. Our payment obligations under the guaranty are limited to the lesser of (i) 25% of SES's negotiated demand charges for the full term of the agreement(s), less any payments made by us pursuant to the guaranty, or (ii) 25% of SES's negotiated demand charges for the remaining initial terms of the agreement(s) as of the first day of the month of services under the agreements for which payment is claimed, which amount shall reflect any reductions in SES's obligations under the agreements.

On September 30, 2008, SES entered into a precedent agreement pursuant to which it will contract for firm gas transportation services on a proposed new pipeline of Fayetteville Express Pipeline LLC (FEP), which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. SES will be a "Foundation Shipper" for the project and will use the new pipeline primarily to deliver gas volumes produced from our operations in the Fayetteville Shale play in central Arkansas. Pending regulatory approvals, the pipeline is expected to be in-service by late 2010 or early 2011. The proposed pipeline will have an estimated ultimate capacity of up to 2.0 Bcf per day. Following the approval of the pipeline by the Federal Energy Regulatory Commission and subject to certain conditions, pursuant to the precedent agreement, we will enter into a firm transportation agreement to transport up to 1,200,000 Dekatherms per day for an initial term of ten years. In connection with the precedent agreement, we delivered to FEP a guaranty of SES's obligations under the precedent agreement and the firm transportation agreements to be entered into thereunder. Initially, and during any period in which SES meets the creditworthiness requirements of the precedent agreement, our payment obligations under the guaranty are zero but will increase upon the occurrence of certain events. Other than the issuance of the notes and the addition of and increase in pipeline volume commitments and the related guaranties, 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 and taking into account the transfer of pension obligations related to the sale of AWG, we expect to record expenses of approximately $6.5 million in 2008 for these plans, of which $5.2 million has been recorded in the first nine months of 2008. As a result of the sale of AWG on July 1, 2008, we transferred pension and other postretirement assets and liabilities related to the employees of AWG to the purchaser. At September 30, 2008, we recognized a liability of $7.6 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 positive working capital of $156.8 million at September 30, 2008, and negative working capital of $67.6 million at December 31, 2007. Current assets increased $526.3 million at September 30, 2008, compared to current assets at December 31, 2007, due to a $424.8 million increase in cash equivalents from proceeds received from the sale of our utility segment and certain oil and gas assets, a $76.4 million increase in accounts receivable, and a $71.8 million increase in our current hedging asset, which were partially offset by a decrease of $58.9 million in current assets held for sale related to our utility segment. Current liabilities increased $302.0 million as a result of an increase of $127.5 million in accounts payable, a $73.8 million increase in current taxes payable, a $60.0 million increase due to the reclassification of our 7.625% Senior Notes, an increase of $27.0 million in our current deferred income taxes related to our hedging activities and an increase of $19.0 million in our current hedging liability.

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 9.5 Bcf at $4.44 per Mcf at September 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 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 6% of accounts receivable at September 30, 2008. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At September 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. 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 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 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 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 closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any losses to date in 2008 related to non-performance and do not anticipate any losses given the information we have currently. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

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 September 30, 2008, the fair value of our financial instruments related to natural gas production and gas-in-storage was a $130.7 million asset and a $4.0 million asset, respectively.

	Volume	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at September 30, 2008 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2008[(1)]	11.9	8.48	—	—	—	10.7
2009[(2)]	77.1	8.33	—	—	—	16.5
2010	36.0	9.04	—	—	—	15.2
Costless Collars:						
2008	17.0	—	7.76	10.70	—	8.1
2009	59.0	—	8.71	11.69	—	61.6
2010	14.0	—	8.29	10.57	—	4.3
Basis Swaps:						
2008	24.5	—	—	—	(0.63)	12.9
2009	26.0	—	—	—	(0.55)	2.9
2010	10.1	—	—	—	(0.65)	(0.1)
2011	1.8	—	—	—	(0.71)	0.1
Matched-Basis Swaps:						
2008	1.5	—	—	—	(0.71)	2.5

(1) Includes fixed-price swaps for 0.4 Bcf relating to future sales from our underground storage facility that have a fair value asset of approximately $1.2 million.

(2) Includes fixed-price swaps for 1.1 Bcf relating to future sales from our underground storage facility that have a fair value asset of $2.8 million.

At September 30, 2008, we had outstanding fixed-price basis differential swaps on 24.5 Bcf of 2008, 26.0 Bcf of 2009, 10.1 Bcf of 2010 and 1.8 Bcf of 2011 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 nine months ended September 30, 2008, we recorded an unrealized gain of $16.6 million related to the differential swaps that did not qualify for hedge accounting treatment and a $10.5 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. As of October 24, 2008 we have basis protected an additional 4.9 Bcf of future gas production subsequent to the end of the quarter.

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 September 30, 2008, our Midstream Services segment had outstanding fair value hedges in place on 0.8 Bcf, 0.7 Bcf and 0.2 Bcf of gas for 2008, 2009 and 2010, 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 October 2008 through December 2010 and have a net fair value asset of $0.1 million as of September 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 September 30, 2008. There were no changes in our internal control over financial reporting during the three months ended September 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.

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(4.1) Second Amendment to Second Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as Administrative Agent, and a lender under the facility, SunTrust Bank as Syndication Agent, Bank of America, N.A., Royal Bank of Canada and Royal Bank of Scotland plc dated February 9, 2007.

(10.1) Separation Agreement between Richard F. Lane and Southwestern Energy Company, effective as of September 3, 2008 (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on September 3, 2008).

(10.2) Consulting Agreement between Richard F. Lane and Southwestern Energy Company, effective as of September 3, 2008 (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on September 3, 2008).

(10.3) Guaranty by and between Southwestern Energy Company and Texas Gas Transmission, LLC, dated as of October 27, 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: October 30, 2008

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