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, 2009**

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 27, 2009
Common Stock, Par Value $0.01 (including associated stock purchase rights)	345,295,309

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2009

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

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, 2008 (the "2008 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

ITEM 1. FINANCIAL STATEMENTS

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 369,963	$ 433,698	$ 1,110,051	$ 1,167,403
Gas marketing	113,642	226,889	356,652	568,032
Oil sales	1,805	9,565	4,680	38,816
Gas gathering	17,443	12,662	50,871	30,134
Other	96	185	(968)	7,090
	502,949	682,999	1,521,286	1,811,475
Operating Costs and Expenses:				
Gas purchases – midstream services	112,956	225,149	353,323	560,490
Gas purchases – gas distribution	—	—	—	61,439
Operating expenses	38,898	23,877	96,576	77,903
General and administrative expenses	31,942	21,055	84,851	70,536
Depreciation, depletion and amortization	113,833	105,230	355,988	300,478
Impairment of natural gas and oil properties	—	—	907,812	—
Taxes, other than income taxes	8,282	8,648	23,963	24,793
	305,911	383,959	1,822,513	1,095,639
Operating Income (Loss)	197,038	299,040	(301,227)	715,836
Interest Expense:				
Interest on debt	13,761	14,205	41,671	46,950
Other interest charges	740	482	2,269	1,749
Interest capitalized	(9,224)	(8,109)	(31,913)	(21,595)
	5,277	6,578	12,027	27,104
Other Income	554	2,354	1,088	2,530
Gain on Sale of Utility Assets	—	57,264	—	57,264
Income (Loss) Before Income Taxes	192,315	352,080	(312,166)	748,526
Provision (Benefit) for Income Taxes:				
Current	(20,704)	61,000	(56,204)	107,500
Deferred	94,809	72,715	(62,378)	176,732
	74,105	133,715	(118,582)	284,232
Net income (loss)	118,210	218,365	(193,584)	464,294
Less: net income (loss) attributable to noncontrolling interest	(44)	197	(108)	547
Net Income (Loss) Attributable to Southwestern Energy	$ 118,254	$ 218,168	$ (193,476)	$ 463,747
Earnings Per Share:				
Net income (loss) attributable to Southwestern Energy stockholders – Basic	$ 0.34	$ 0.64	$ (0.56)	$ 1.36
Net income (loss) attributable to Southwestern Energy stockholders - Diluted	$ 0.34	$ 0.63	$ (0.56)	$ 1.34
Weighted Average Common Shares Outstanding:				
Basic	343,717,232	342,312,845	343,087,065	341,595,957
Diluted	349,000,241	346,712,565	343,087,065	346,459,853

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2009	December 31, 2008
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 9,659	$ 196,277
Accounts receivable	199,011	254,557
Inventories	30,309	50,377
Hedging asset	230,278	343,320
Other	64,579	38,732
Total current assets	533,836	883,263
Property and Equipment:		
Gas and oil properties (using the full cost method), including costs excluded from amortization of $624.4 million in 2009 and $540.6 million in 2008	6,015,561	4,836,077
Gathering systems	500,867	341,474
Gas in underground storage	13,349	13,349
Other	179,815	138,014
Total property and equipment	6,709,592	5,328,914
Less: Accumulated depreciation, depletion and amortization	2,882,350	1,615,307
Property and equipment, net	3,827,242	3,713,607
Other Assets	97,065	163,288
TOTAL ASSETS	$ 4,458,143	$ 4,760,158
LIABILITIES AND EQUITY		
Current Liabilities:		
Short-term debt	$ 1,200	$ 61,200
Accounts payable	348,518	451,597
Taxes payable	21,180	31,951
Interest payable	9,914	20,857
Advances from partners	71,526	70,603
Hedging liability	12,281	10,899
Current deferred income taxes	81,059	122,448
Other	15,838	10,758
Total current liabilities	561,516	780,313
Long-Term Debt	958,300	674,200
Other Liabilities:		
Deferred income taxes	632,890	721,707
Long-term hedging liability	10,265	5,934
Pension and other postretirement liabilities	12,560	15,436
Other long-term liabilities	53,047	44,605
	708,762	787,682
Commitments and Contingencies		
Equity:		
Southwestern Energy stockholders' equity		
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 345,256,980 shares in 2009 and 343,624,956 in 2008	3,453	3,436
Additional paid-in capital	827,040	811,492
Retained earnings	1,256,501	1,449,977
Accumulated other comprehensive income	136,999	247,665
Common stock in treasury, 203,472 shares in 2009 and 225,050 in 2008	(4,316)	(4,740)
Total Southwestern Energy stockholders' equity	2,219,677	2,507,830
Noncontrolling interest	9,888	10,133
Total equity	2,229,565	2,517,963
TOTAL LIABILITIES AND EQUITY	$ 4,458,143	$ 4,760,158

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

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

	For the nine months ended September 30, 2009	For the nine months ended September 30, 2008
	(in thousands)	
Cash Flows From Operating Activities		
Net income (loss)	$ (193,584)	$ 464,294
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	357,218	301,801
Impairment of natural gas and oil properties	907,812	—
Deferred income taxes	(62,378)	176,732
Impairment of natural gas inventory and other	5,459	—
Gain on sale of utility assets	—	(57,264)
Unrealized (gain) loss on derivatives	6,535	(5,956)
Stock-based compensation expense	8,699	5,379
Gain on sale of property and equipment	—	(392)
Distributions to noncontrolling interest in partnership	(137)	(508)
Change in assets and liabilities:		
Accounts receivable	55,546	(59,690)
Inventories	7,284	(32,397)
Accounts payable	(61,416)	115,388
Taxes payable	(10,771)	67,834
Interest payable	(10,943)	9,784
Advances from partners and customer deposits	923	24,432
Deferred tax benefit – stock options	—	(42,197)
Other assets and liabilities	(20,721)	(533)
Net cash provided by operating activities	989,526	966,707
Cash Flows From Investing Activities		
Capital investments	(1,374,047)	(1,287,324)
Proceeds from sale of property and equipment	—	732,924
Net proceeds from sale of utility assets	—	213,721
Other	(4,585)	(816)
Net cash used in investing activities	(1,378,632)	(341,495)
Cash Flows From Financing Activities		
Payments on short-term debt	(60,600)	(600)
Payments on revolving long-term debt	(879,400)	(1,843,600)
Borrowings under revolving long-term debt	1,164,100	1,001,400
Proceeds from issuance of long-term debt	—	600,000
Debt issuance costs and revolving credit facility costs	—	(8,895)
Excess tax benefit for stock-based compensation	—	42,197
Change in bank drafts outstanding	(25,783)	5,402
Proceeds from exercise of common stock options	4,171	3,240
Net cash provided by (used in) financing activities	202,488	(200,856)
Increase (decrease) in cash and cash equivalents	(186,618)	424,356
Cash and cash equivalents at beginning of year (1)	196,277	1,832
Cash and cash equivalents at end of period	$ 9,659	$ 426,188

(1) Cash and cash equivalents at the beginning of the year for 2008 include $1.1 million classified as "held for sale." See Note 4 for additional information.

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Southwestern Energy Stockholders							
	Common Stock							
	Shares Issued	Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Common Stock in Treasury	Noncontrolling Interest	Total
	(in thousands)							
Balance at December 31, 2008	343,625	$ 3,436	$ 811,492	$1,449,977	$ 247,665	$ (4,740)	$ 10,133	$ 2,517,963
Comprehensive income (loss):								
Net loss	—	—	—	(193,476)	—	—	(108)	(193,584)
Change in value of derivatives	—	—	—	—	(111,255)	—	—	(111,255)
Change in value of pension and other postretirement liabilities	—	—	—	—	589	—	—	589
Total comprehensive loss							(108)	(304,250)
Stock-based compensation	—	—	11,190	—	—	—	—	11,190
Exercise of stock options	1,618	17	4,154	—	—	—	—	4,171
Issuance of restricted stock	22	—	—	—	—	—	—	—
Cancellation of restricted stock	(8)	—	—	—	—	—	—	—
Treasury stock – non-qualified plan	—	—	204	—	—	424	—	628
Distributions to noncontrolling interest in partnership	—	—	—	—	—	—	(137)	(137)
Balance at September 30, 2009	345,257	$ 3,453	$ 827,040	$1,256,501	$ 136,999	$ (4,316)	$ 9,888	$ 2,229,565

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Net income (loss)	$ 118,210	$ 218,365	$ (193,584)	$ 464,294
Change in value of derivatives:				
Current period reclassification to earnings (1)	(101,336)	32,129	(289,432)	67,775
Current period ineffectiveness (2)	4,969	(19,748)	5,021	6,533
Current period change in derivative instruments (3)	(5,383)	513,785	173,156	(23,970)
Total change in value of derivatives	(101,750)	526,166	(111,255)	50,338
Change in value of pension and other postretirement liabilities				
Sale of utility – divestiture, curtailment and settlement (4)	—	9,040	—	9,040
Current period change in value of pension and other postretirement liabilities (5)	199	(3,890)	589	(3,471)
Total change in value of pension and other postretirement liabilities	199	5,150	589	5,569
Comprehensive income (loss)	16,659	749,681	(304,250)	520,201
Less: comprehensive income (loss) attributable to the noncontrolling interest	(44)	197	(108)	547
Comprehensive income (loss) attributable to Southwestern Energy	$ 16,703	$ 749,484	$ (304,142)	$ 519,654

(1) Current period reclassification to earnings is net of ($65.4), $19.7, ($180.9) and $41.5 million in taxes for the three months ended September 30, 2009 and 2008, and the nine months ended September 30, 2009 and 2008, respectively.

(2) Current period ineffectiveness is net of $3.2, ($12.1), $3.2 and $4.0 million in taxes for the three months ended September 30, 2009 and 2008, and the nine months ended September 30, 2009 and 2008, respectively.

(3) Current period change in derivative instruments is net of ($3.5), $314.9, $109.5 and ($14.7) million in taxes for the three months ended September 30, 2009 and 2008, and the nine months ended September 30, 2009 and 2008, respectively.

(4) Sale of utility – divestiture, curtailment and settlement is net of $5.5 and $5.5 million in taxes for the three and nine months ended September 30, 2008, respectively.

(5) Current period change in the value of pension and other postretirement liabilities is net of $0.1, ($2.3), $0.3 and ($2.1) million in taxes for the three months ended September 30, 2009 and 2008, and the nine months ended September 30, 2009 and 2008, respectively.

See the accompanying notes which are an integral part of these unaudited condensed consolidated financial statements.

(1) BASIS OF PRESENTATION

Southwestern Energy Company (including its subsidiaries, collectively, the "Company," "Southwestern," "we," "us," "its," and "our") is an independent energy company primarily focused on the exploration and production of natural gas. The Company engages in natural gas and oil exploration and production and natural gas gathering and marketing through its subsidiaries. Southwestern's exploration and production ("E&P") activities are currently concentrated in Arkansas, Oklahoma, Pennsylvania and Texas. Southwestern's marketing and gas gathering business ("Midstream Services") is concentrated in the core areas of its E&P operations.

The accompanying unaudited condensed consolidated financial statements were prepared using accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and in accordance with the rules and regulations of the SEC. Certain information relating to the Company's organization and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been appropriately condensed or omitted in this Quarterly Report on Form 10-Q. The Company believes that the disclosures made are adequate to make the information presented not misleading.

The unaudited condensed consolidated financial statements contained in this report include all normal and recurring material adjustments that, in the opinion of management, are necessary for a fair presentation of the financial position, results of operations and cash flows for the interim periods presented herein. It is recommended that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and the notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2008 ("2008 Annual Report on Form 10-K").

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 Company's 2008 Annual Report on Form 10-K.

In June 2009, the Company implemented the Financial Accounting Standards Board Accounting Standards Codification ("FASB ASC"). The implementation establishes the FASB ASC as the source of authoritative accounting principles to be applied in the preparation of financial statements in conformity with GAAP. The FASB ASC does not change GAAP and its implementation did not have a material impact on the Company's consolidated financial statements.

On January 1, 2009, the Company implemented certain provisions of FASB ASC Topic 810-10, "Consolidation – Overall," which establish accounting and reporting standards for (1) ownership interests in subsidiaries held by others, (2) the amount of consolidated net income attributable to the controlling and noncontrolling interests, (3) changes in the controlling ownership interest, (4) the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated and (5) disclosures that clearly identify and distinguish between the interests of the controlling and noncontrolling owners. The implementation resulted in changes to the Company's presentation for noncontrolling interests and did not have a material impact on the Company's results of operations and financial condition.

On January 1, 2009, the Company implemented certain provisions of FASB ASC Topic 815-10, "Derivatives and Hedging – Overall," which require enhanced disclosure about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The implementation did not have a material impact on the Company's results of operations and financial condition.

On January 1, 2009, the Company implemented certain provisions of FASB ASC Topic 820-10, "Fair Value Measurements and Disclosures – Overall," which require the fair value application 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). The implementation did not have a material impact on the Company's results of operations and financial condition.

On June 30, 2009, the Company implemented certain provisions of FASB ASC Topic 825-10, "Financial Instruments – Overall," which require that the (1) fair value disclosures required for certain financial instruments be included in interim financial statements and (2) public companies disclose the method and significant assumptions used to estimate the fair value of those financial instruments and to discuss any changes of method or assumptions, if any, during the reporting period. The implementation did not have a material impact on the Company's results of operations and financial condition.

On June 30, 2009, the Company implemented certain provisions of FASB ASC Topic 855-10, "Subsequent Events – Overall," which establish the general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Among other things, the Company is now required to disclose the date through which it has evaluated subsequent events and the basis for that date. The implementation did not have a material impact on the Company's results of operations and financial condition.

Certain reclassifications have been made to the prior year's financial statements to conform to the 2009 presentation. The effects of the reclassifications were not material to the Company's unaudited condensed consolidated financial statements.

(2) GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development, and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs, less accumulated amortization and related deferred income taxes, 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 a periodic report may be utilized to calculate the ceiling value of reserves.

At March 31, 2009, the net capitalized costs of our gas and oil properties exceeded the ceiling by approximately \$558.3 million (net of tax) and resulted in a non-cash ceiling test impairment in the first quarter of 2009. Using the quoted market price for Henry Hub natural gas on October 23, 2009 of \$4.98 per MMBtu and \$77.75 per barrel for West Texas Intermediate oil, adjusted for market differentials, the Company's net book value of natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment in the third quarter. The ceiling value of the Company's reserves based upon quoted market prices at September 30, 2009 of \$3.30 per MMBtu for Henry Hub natural gas and \$67.00 per barrel for West Texas Intermediate oil, adjusted for market differentials, would have exceeded the ceiling amount by \$228.3 million (net of taxes), including the effect of hedges. Cash flow hedges of gas production in place increased the ceiling value by approximately \$347.7 million and \$208.2 million at September 30, 2009 and October 23, 2009, respectively. Decreases in market prices as well as changes in production rates, levels of reserves, 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-month periods ended September 30, 2009 and 2008:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
Net income (loss) attributable to Southwestern Energy (in thousands)	$ 118,254	$ 218,168	$ (193,476)	$ 463,747
Number of common shares:				
Weighted average outstanding	343,717,232	342,312,845	343,087,065	341,595,957
Issued upon assumed exercise of outstanding stock options	4,859,651	3,971,851	—	4,445,642
Effect of issuance of nonvested restricted common shares	423,358	427,869	—	418,254
Weighted average and potential dilutive outstanding(1)	349,000,241	346,712,565	343,087,065	346,459,853
Earnings per share:				
Net income (loss) attributable to Southwestern Energy stockholders – basic	$ 0.34	$ 0.64	$ (0.56)	$ 1.36
Net income (loss) attributable to Southwestern Energy stockholders – diluted	$ 0.34	$ 0.63	$ (0.56)	$ 1.34

(1) Options for 640,105 shares and 53,303 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2009 because they would have had an antidilutive effect. Options for 40,705 shares and 78,936 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2008 because they would have had an antidilutive effect. Due to the net loss for the nine months ended September 30, 2009, options for 6,964,471 shares and 844,051 shares of restricted stock were antidilutive and excluded from the calculation. Options for 349,410 shares and 40,597 shares of restricted stock were excluded from the calculation for the nine months ended September 30, 2008 because they would have had an antidilutive effect.

(4) DIVESTITURES

In November 2007, the Company entered into an agreement to sell all of the capital stock of its wholly-owned subsidiary, Arkansas Western Gas Company (“AWG”), for $224 million plus working capital. On July 1, 2008, the transaction was closed and the Company received $223.5 million (net of expenses related to the sale). In order to receive regulatory approval for the sale and certain related transactions, the Company paid $9.8 million to AWG for the benefit of its customers. The Company recorded a $57.3 million pre-tax gain on the sale of AWG in the third quarter of 2008. The operating results and cash flows from AWG through June 30, 2008 are included in the unaudited condensed consolidated statements of operations and statements of cash flows. As a result of completion of the sale of AWG, the Company is no longer engaged in any natural gas distribution operations.

In the second quarter of 2008, the Company sold certain natural gas and oil leases, wells and gathering equipment in its Fayetteville Shale play for $518.3 million. Additionally, in the second and third quarters of 2008, the Company sold various natural gas and oil properties in the Gulf Coast and Permian Basin for approximately $240 million in the aggregate. All proceeds from the sales of natural gas and oil properties were credited to the full cost pool. The operating results and cash flows from the divested properties are included in the unaudited condensed consolidated statements of operations and statements of cash flows for the three- and nine-month periods ended September 30, 2008.

(5) DEBT

The components of debt as of September 30, 2009 and December 31, 2008 consisted of the following:

	September 30, 2009	December 31, 2008
	(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	1,200	61,200
Long-term debt:		
Variable rate (1.126% at September 30, 2009) unsecured revolving credit facility	284,700	—
7.5% Senior Notes due 2018	600,000	600,000
7.21% Senior Notes due 2017	40,000	40,000
7.15% Senior Notes due 2018	33,600	34,200
Total long-term debt	958,300	674,200
Total debt	$ 959,500	$ 735,400

The Company has an unsecured revolving credit facility which expires in February 2012 ("Credit Facility"). The Credit Facility has 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. As of September 30, 2009, the Company had $284.7 million in borrowings outstanding under the Credit Facility with a weighted average interest rate of 1.126%. In the second quarter of 2009, the 7.625% Senior Notes were put to the Company and the Company utilized funds available under the Credit Facility to pay the note holders $62.1 million in principal and accrued interest on May 1, 2009.

The Credit Facility is currently guaranteed by the Company's 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. In addition to the subsidiary guarantees, the Credit Facility restricts the ability of the Company's subsidiaries to incur debt and contains covenants which impose certain restrictions on the Company. Under the terms of the Credit Facility, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") to interest expense of 3.5 or above. At September 30, 2009, the Company was in compliance with the covenants of its debt agreements.

(6) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to commodity price risk which impacts the predictability of its cash flows related to the sale of natural gas and oil. The primary risk managed by the Company's use of certain derivative financial instruments is commodity price risk. These derivative financial instruments allow the Company to limit its price exposure to a portion of its projected natural gas sales. At September 30, 2009 and December 31, 2008, the Company's derivative financial instruments consisted of price swaps, costless collars and basis swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps — The Company receives a fixed price for the contract and pays a floating market price to the counterparty.

Floating price swaps — The Company receives a floating market price from the counterparty and pays a fixed price.

Costless-collars — Contain a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Basis swaps	Matched and unmatched arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

GAAP requires that all derivatives be recognized in the balance sheet as either an asset or liability and be measured at fair value. Under GAAP, certain criteria must be satisfied in order for derivative financial instruments to be classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative's gains and losses to be recorded as a component of other comprehensive income. Gains and losses on derivatives that are not elected for hedge accounting treatment or that do not meet hedge accounting requirements are recorded in earnings.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy at the time the transactions are entered into and the Company closely 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 will be able to meet its obligations to the Company.

None of the Company's derivative instruments contain credit-risk-related contingent features other than one derivative instrument which expires in December 2009. The credit-risk-related contingent feature, which requires the posting of cash collateral, is triggered when a net liability owed to that counterparty exceeds a threshold amount. The required cash collateral amount is equal to the net liability owed to the counterparty less the threshold amount. This derivative instrument was in a net asset position as of September 30, 2009 and no amounts have been remitted as collateral to the counterparty. The Company has not incurred any credit-related losses associated with its derivative activities and believes that its counterparties will continue to be able to meet their obligations under these transactions.

The balance sheet classification of the assets and liabilities related to derivative financial instruments are summarized below at September 30, 2009 and December 31, 2008:

	Derivative Assets			
	2009		2008	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
		(in thousands)		
Derivatives designated as hedging instruments				
Fixed and floating price swaps	Hedging asset	$ 136,638	Hedging asset	$ 174,985
Costless-collars	Hedging asset	93,640	Hedging asset	165,671
Fixed and floating price swaps	Other Assets	20,762	Other Assets	66,349
Costless-collars	Other Assets	6,409	Other Assets	26,202
Total derivatives designated as hedging instruments		$ 257,449		$ 433,207
Derivatives not designated as hedging instruments				
Basis swaps	Hedging asset	$ —	Hedging asset	$ 2,664
Basis swaps	Other Assets	—	Other Assets	1,844
Total derivatives not designated as hedging instruments		$ —		$ 4,508
Total derivative assets		$ 257,449		$ 437,715

	Derivative Liabilities			
	2009		2008	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments				
Fixed and floating price swaps	Hedging liability	$ 946	Hedging liability	$ 2,679
Costless-collars	Hedging liability	729	Hedging liability	5,670
Fixed and floating price swaps	Long-term hedging liability	7,101	Long-term hedging liability	557
Costless-collars	Long-term hedging liability	769	Long-term hedging liability	5,142
Total derivatives designated as hedging instruments		$ 9,545		$ 14,048
Derivatives not designated as hedging instruments				
Basis swaps	Hedging liability	$ 10,606	Hedging liability	$ 2,550
Basis swaps	Long-term hedging liability	2,395	Long-term hedging liability	235
Total derivatives not designated as hedging instruments		$ 13,001		$ 2,785
Total derivative liabilities		$ 22,546		$ 16,833

Cash Flow Hedges

The reporting of gains and losses on cash flow derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gains and losses on the derivative hedging instrument are recorded in other comprehensive income until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from the derivative hedging instrument is recognized in earnings immediately.

As of September 30, 2009, the Company had cash flow hedges on the following volumes of gas production:

Natural Gas (Bcf):

Fixed price swaps:	
2009	15.0
2010	36.0
2011	20.0
Costless-collars:	
2009	18.0
2010	14.0

As of September 30, 2009, the Company recorded a net gain to other comprehensive income related to its hedging activities of $147.6 million. These amounts are net of a deferred income tax liability recorded as of September 30, 2009 of $90.5 million. The amount recorded in other comprehensive income will be relieved over time and taken to the statement of operations as the physical transactions being hedged occur. Assuming the market prices of gas futures as of September 30, 2009 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $136.2 million from accumulated other comprehensive income to earnings during the next 12 months. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to gas sales in the unaudited condensed consolidated statements of operations. Gas sales included a realized gain from settled contracts of $470.3 million for the nine-month period ended September 30, 2009 compared to a realized loss of $109.4 million during the nine-month period ended September 30, 2008. Volatility in earnings and other comprehensive income may occur in the future as a result of the application of the Company's derivative activities.

The following tables summarize the before tax effect of all cash flow hedges on the unaudited condensed consolidated statements of operations for the three- and nine-month periods ended September 30, 2009 and 2008:

Derivative Instrument	Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion) — For the three months ended September 30, 2009	2008	For the nine months ended September 30, 2009	2008
	(in thousands)			
Fixed price swaps	$ (6,114)	$ 491,985	$ 183,699	$ (75,002)
Costless-collars	$ (2,741)	$ 272,457	$ 98,951	$ 52,683
Matched-basis swaps	$ —	$ 488	$ —	$ 4,678

Derivative Instrument	Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion) — For the three months ended September 30, 2009	2008	For the nine months ended September 30, 2009	2008
		(in thousands)			
Fixed price swaps	Gas Sales	$ 116,216	$ (47,763)	$ 282,264	$ (110,709)
Costless-collars	Gas Sales	$ 50,487	$ (5,794)	$ 188,060	$ (966)
Matched-basis swaps	Gas Sales	$ —	$ 1,683	$ —	$ 2,308

Derivative Instrument	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion) — For the three months ended September 30, 2009	2008	For the nine months ended September 30, 2009	2008
		(in thousands)			
Fixed price swaps	Gas Sales	$ 4,760	$ 18,789	$ 4,931	$ (4,049)
Costless-collars	Gas Sales	$ 3,415	$ 13,062	$ 3,300	$ (6,487)

Fair Value Hedges

For fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item are recognized in current earnings. As of September 30, 2009, the Company had fair value hedges on the following volumes of gas production:

Natural Gas (Bcf):

Floating price swaps:	
2009	0.1
2010	0.3
2011	0.1
2012	0.1

The following table summarizes the before tax effect of all fair value hedges on the unaudited condensed consolidated statements of operations for the three months ended September 30, 2009 and 2008:

Derivative Instrument	Income Statement Classification of Gain (Loss)	Unrealized Gain (Loss) Recognized in Earnings 2009	2008	Realized Gain (Loss) Recognized in Earnings 2009	2008
		(in thousands)			
Floating price swaps	Gas Sales	$ (14)	$ (400)	$ (370)	$ (699)

The following table summarizes the before tax effect of all fair value hedges on the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2009 and 2008:

Derivative Instrument	Income Statement Classification of Gain(Loss)	Unrealized Gain (Loss) Recognized in Earnings 2009	Unrealized Gain (Loss) Recognized in Earnings 2008	Realized Gain (Loss) Recognized in Earnings 2009	Realized Gain (Loss) Recognized in Earnings 2008
		(in thousands)			
Floating price swaps	Gas Sales	$ (41)	$ (65)	$ 1,338	$ (841)

Other Derivative Contracts

Although the Company's basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company's derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. Basis swap derivative instruments that do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under hedging assets, other assets and hedging liabilities, and all realized and unrealized gains and losses related to these contracts are recognized immediately in the unaudited condensed consolidated statements of operations as a component of gas sales. For the nine-month period ended September 30, 2009, gas sales included an unrealized loss of $14.7 million for non-qualifying basis swaps. For the nine-month period ended September 30, 2008, gas sales included an unrealized gain of $16.6 million for non-qualifying basis swaps.

As of September 30, 2009, the Company had basis swaps on the following volumes of gas production that did not qualify for hedge treatment:

Natural Gas (Bcf):

Basis Swaps:	
2009	22.1
2010	46.5
2011	9.0

The following table summarizes the before tax effect of basis swaps that did not qualify for hedge accounting on the unaudited condensed consolidated statements of operations for the three months ended September 30, 2009 and 2008:

Derivative Instrument	Income Statement Classification of Gain (Loss)	Unrealized Gain (Loss) Recognized in Earnings 2009	Unrealized Gain (Loss) Recognized in Earnings 2008	Realized Gain (Loss) Recognized in Earnings 2009	Realized Gain (Loss) Recognized in Earnings 2008
		(in thousands)			
Basis swaps	Gas Sales	$ (8,657)	$ (5,150)	$ (4,370)	$ 11,980

The following table summarizes the before tax effect of basis swaps that did not qualify for hedge accounting on the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2009 and 2008:

Derivative Instrument	Income Statement Classification of Gain(Loss)	Unrealized Gain (Loss) Recognized in Earnings 2009	Unrealized Gain (Loss) Recognized in Earnings 2008	Realized Gain (Loss) Recognized in Earnings 2009	Realized Gain (Loss) Recognized in Earnings 2008
		(in thousands)			
Basis swaps	Gas Sales	$ (14,725)	$ 16,557	$ (3,004)	$ 18,616

(7) FAIR VALUE MEASUREMENTS

At September 30, 2009, the carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities on the unaudited condensed consolidated balance sheets approximate fair value because of their short term nature. For debt and commodity hedges, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's 7.5% Senior Notes due 2018, 7.21% Senior Notes due 2017 and 7.15% Senior Notes due 2018 were based on the September 30, 2009 yield of the Company's publicly-traded debt. The yield of the Company's publicly-traded 7.5% Senior Notes due 2018 was 7.3% at September 30, 2009. Borrowings of $284.7 million under the Company's unsecured revolving credit facility at September 30, 2009 approximate fair value.

Commodity Hedges: The fair value of all hedging financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The carrying amounts and estimated fair values of the Company's financial instruments as of September 30, 2009 and December 31, 2008 were as follows:

	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	$ 9,659	$ 9,659	$ 196,277	$ 196,277
Total debt	$ 959,500	$ 968,401	$ 735,400	$ 648,616
Commodity hedges	$ 234,903	$ 234,903	$ 421,410	$ 421,410

Effective January 1, 2008, the Company partially implemented certain provisions of FASB ASC 820-10, "Fair Value Measurements and Disclosures – Overall," which defines fair value, provides a framework for measuring fair value under GAAP and expands the required disclosures about fair value measurements. Additionally, on January 1, 2008, the Company implemented certain provisions of FASB ASC 825-10, "Financial Instruments – Overall," which allow 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 for any of its financial instruments that are not currently measured at fair value.

GAAP 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 have the highest priority.

Level 2 valuations - Consist of quoted market information for the calculation of fair market value.

Level 3 valuations - Consist of internal estimates and have the lowest priority.

Pursuant to GAAP, the Company has classified its derivatives into these levels depending upon the data relied on to determine the fair values. The Company's fixed-price and floating-price swaps are estimated using internal discounted cash flow calculations using the NYMEX futures index and are designated as Level 2. The fair values of costless-collars and 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, 2009 (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	$ —	$ 157,400	$ 100,049	$ 257,449
Derivative liabilities	—	(8,047)	(14,499)	(22,546)
Total	$ —	$ 149,353	$ 85,550	$ 234,903

The table below presents reconciliations for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three- and nine-month periods ended September 30, 2009. 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 table 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, 2009.

Total net gains and losses for Level 3 derivatives for the three- and nine-month periods ended September 30, 2009 are provided below:

	For the three months ended September 30, 2009	For the nine months ended September 30, 2009
	(in thousands)	
Balance at beginning of period	$ 140,606	$ 182,823
Total gains or losses (realized/unrealized):		
Included in earnings	40,874	175,945
Included in other comprehensive income (loss)	(49,814)	(85,810)
Purchases, issuances and settlements	(46,116)	(187,408)
Transfers into/out of Level 3	—	—
Balance at September 30, 2009	$ 85,550	$ 85,550
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of September 30, 2009	$ (5,242)	$ (11,463)

(8) 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 gathering fees associated with the transportation of natural gas to market and through the marketing of both Company and third-party produced gas volumes. Revenues for the Natural Gas Distribution segment arose from the transportation and retail sale of natural gas by AWG. As a result of the disposition 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 2008 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. 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, 2009:					
Revenues from external customers	$ 371,864	$ 131,085	$ —	$ —	$ 502,949
Intersegment revenues	(830)	229,126	—	112	228,408
Operating income (loss)	172,038	25,100	—	(100)	197,038
Interest and other income(1)	551	—	—	3	554
Depreciation, depletion and amortization expense	108,432	5,205	—	196	113,833
Interest expense(1)	3,819	1,458	—	—	5,277
Provision (benefit) for income taxes(1)	65,268	8,875	—	(38)	74,105
Assets	3,775,982	596,611	—	85,550 (2)	4,458,143
Capital investments(3)	333,927	64,986	—	9,860	408,773
Three months ended September 30, 2008:					
Revenues from external customers	$ 443,327	$ 239,550	$ —	$ 122	$ 682,999
Intersegment revenues	14,846	443,621	—	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
Nine months ended September 30, 2009:					
Revenues from external customers	$ 1,113,524	$ 407,523	$ —	$ 239	$ 1,521,286
Intersegment revenues	8,276	683,326	—	336	691,938
Operating income (loss)	(381,422) (4)	80,254	—	(59)	(301,227)
Interest and other income(1)	1,079	—	—	9	1,088
Depreciation, depletion and amortization expense	341,920	13,506	—	562	355,988
Impairment of natural gas and oil properties	907,812	—	—	—	907,812
Interest expense(1)	9,671	2,356	—	—	12,027
Provision (benefit) for income taxes(1)	(148,163)	29,601	—	(20)	(118,582)
Assets	3,775,982	596,611	—	85,550 (2)	4,458,143
Capital investments(3)	1,186,409	167,442	—	14,350	1,368,201
Nine months ended September 30, 2008:					
Revenues from external customers	$ 1,097,839	$ 598,557	$ 114,957	$ 122	$ 1,811,475
Intersegment revenues	50,076	1,129,697	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

(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 cash and cash equivalents, for non-reportable segments.
(3) Capital investments include reductions of \$4.2 million and \$12.4 million for the three- and nine-month periods ended September 30, 2009, respectively, and 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, relating to the change in accrued expenditures between periods.
(4) The operating loss for the E&P segment for the nine months ended September 30, 2009 includes a \$907.8 million non-cash ceiling test impairment of our natural gas and oil properties resulting from the significant decline in natural gas prices as of March 31, 2009 that was incurred during the first quarter of 2009.

Included in intersegment revenues of the Midstream Services segment are $158.6 million and $407.0 million for the three months ended September 30, 2009 and 2008, respectively, and $515.6 million and $1,035.1 million for the nine months ended September 30, 2009 and 2008, respectively, for the 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 during 2008 were priced in accordance with terms of existing contracts and current market conditions. Corporate assets include cash and cash equivalents, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. All of the Company's operations are located within the United States.

(9) INTEREST AND INCOME TAXES

Interest payments totaling $52.6 million and $37.0 million were made for the nine-month periods ended September 30, 2009 and 2008, respectively.

Income tax payments totaling $0.1 million and $46.5 million were made for the nine-month periods ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009, the Company received a $41.8 million income tax refund.

The current and deferred tax portions of the Company's provision (benefit) for income taxes for the three- and nine-month periods ended September 30, 2009 and 2008 are summarized below:

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Current	$ (20,704)	$ 61,000	$ (56,204)	$ 107,500
Deferred	94,809	72,715	(62,378)	176,732
Provision (benefit) for income taxes	$ 74,105	$ 133,715	$ (118,582)	$ 284,232

For the three months ended March 31, 2009, the Company recognized an increase of approximately $50 million in unrecognized tax benefits related to alternative minimum taxes associated with uncertain tax positions. These unrecognized tax benefits were subsequently reduced, and as of September 30, 2009, the Company has no unrecognized tax benefits. The Company does not expect to be subject to current income taxes in 2009.

(10) CONTINGENCIES AND COMMITMENTS

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 financial position or reported results of operations of the Company.

(11) EQUITY

On April 8, 2009, the Company's Board of Directors approved and the Company entered into, a Second Amended and Restated Rights Agreement ("Rights Agreement"), dated as of April 9, 2009, between the Company and Computershare Trust Company, N.A., which amended, restated, superseded and replaced the Amended and Restated Rights Agreement dated as of April 12, 1999, as amended. The Rights Agreement extends the term of the agreement until April 8, 2019 and amends each Right (which initially represented the right to purchase one share of the Common Stock) to represent the right to purchase, when exercisable, a unit consisting of one one-thousandth of a share ("Unit") of Series A Junior Participating Preferred Stock, par value $0.01 per share ("Series A Preferred Stock") at a purchase price of $150.00 per Unit ("Purchase Price"), subject to adjustment.

In connection with the Rights Agreement, the Board of Directors approved the Certificate of Designation, Preferences and Rights ("Certificate of Designation") establishing the Series A Preferred Stock, which was filed with the Secretary of State of the State of Delaware on April 9, 2009, and reserved 1,000,000 shares for issuance under the Rights Agreement.

Pursuant to the Certificate of Designation, when issued, each share of the Series A Preferred Stock entitles the holder thereof to 1,000 votes, subject to adjustment, on all matters submitted to a vote of the stockholders of the Company. Except as otherwise set forth in the Certificate of Designation or provided by law, the holders of shares of the Series A Preferred Stock and the holders of shares of the Common Stock will vote together as one class on all matters submitted to a vote of stockholders 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 12 of the Notes to Consolidated Financial Statements included in Item 8 of the 2008 Annual Report on Form 10-K.

For the three- and nine-months ended September 30, 2009, the Company recorded compensation cost of $1.2 million and $3.5 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.5 million and $1.5 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. As of September 30, 2009, a total of $8.5 million of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods. For the three- and nine-months ended September 30, 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.

For the three- and nine-months ended September 30, 2009, the Company recorded compensation cost of $1.2 million and $3.4 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $0.9 million and $2.8 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, 2009, there was $14.5 million of total unrecognized compensation cost related to nonvested shares of restricted stock. For the three- and nine-months ended September 30, 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.

The following tables summarize stock option activity for the nine months ended September 30, 2009 and provide information for options outstanding as of September 30, 2009.

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2008	7,396,537	$ 7.44
Granted	93,875	36.01
Exercised	(1,618,063)	2.58
Forfeited or expired	(7,000)	31.21
Outstanding at September 30, 2009	5,865,349	$ 9.21
Exercisable at September 30, 2009	4,846,498	$ 4.92

For the nine months ended September 30, 2009 there were 93,875 options granted compared to 65,800 options granted during the first nine months of 2008. The total intrinsic value of options exercised during the first nine months of 2009 and 2008 was $63.3 million and $57.4 million, respectively.

	Options Outstanding				Options Exercisable			
Range of Exercise Prices	Options Outstanding at September 30, 2009	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at September 30, 2009	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)
$0.75 - $1.00	1,019,351	$ 0.93	1.2		1,019,351	$ 0.93	1.2	
$1.01 - $2.50	1,519,682	1.39	2.8		1,519,682	1.39	2.8	
$2.51 - $16.75	1,627,234	4.10	3.5		1,627,234	4.10	3.5	
$16.76 - $30.00	1,060,112	22.15	4.3		668,882	20.43	3.9	
$30.01 - $45.19	638,970	32.53	6.2		11,349	39.50	5.8	
	5,865,349	$ 9.21	3.4	$ 196,334	4,846,498	$ 4.92	2.9	$ 183,010

The following table summarizes restricted stock activity for the nine months ended September 30, 2009.

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2008	843,430	$ 27.66
Granted	40,480	27.01
Vested	(50,797)	28.46
Forfeited	(8,119)	29.81
Unvested shares at September 30, 2009	824,994	$ 27.55

(13) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has defined pension and postretirement benefit plans which cover substantially all of the Company's employees. Net periodic pension and other postretirement benefit costs include the following components for the three- and nine-month periods ended September 30, 2009 and 2008:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Service cost	$ 1,287	$ 1,033	$ 3,861	$ 3,849
Interest cost	719	695	2,155	3,113
Expected return on plan assets	(703)	(692)	(2,107)	(3,201)
Amortization of prior service cost	84	84	251	328
Amortization of net loss	212	40	635	389
Net periodic benefit cost	1,599	1,160	4,795	4,478
Curtailment and settlement cost(1)	—	4,630	—	4,630
Total benefit cost	$ 1,599	$ 5,790	$ 4,795	$ 9,108

	Postretirement Benefits			
	For the three months ended September 30,		For the nine month ended September 30,	
	2009	2008	2009	2008
	(in thousands)			
Service cost	$ 174	$ 126	$ 522	$ 456
Interest cost	33	31	101	186
Expected return on plan assets	—	—	—	(48)
Amortization of transition obligation	16	15	48	59
Amortization of prior service cost	4	2	11	8
Amortization of net loss	2	—	6	34
Net periodic benefit cost	229	174	688	695
Curtailment and settlement benefit(1)	—	(216)	—	(216)
Total benefit cost (benefit)	$ 229	$ (42)	$ 688	$ 479

(1) Related to the sale of AWG and the resulting transfer of certain pension and other postretirement assets and liabilities to the purchaser of AWG. Accordingly, the net curtailment and settlement cost was included as an offset to the gain recognized on the sale of AWG.

The Company currently expects to contribute $9.0 million to the pension plans and less than $0.1 million to the postretirement benefit plans in 2009. As of September 30, 2009, $7.4 million has been contributed to the pension plans and less than $0.1 million has been contributed to the postretirement benefit plans.

The Company maintains a non-qualified defined contribution supplemental retirement savings plan ("Non-Qualified Plan") for certain key employees who may elect to defer and contribute a portion of their compensation, as permitted by the plan. Shares of the Company's common stock purchased under the terms of the Non-Qualified Plan are presented as treasury stock. As of September 30, 2009, treasury stock held by the Company under the terms of the Non-Qualified Plan totaled 203,472 shares compared to 225,050 shares at December 31, 2008.

(14) INVENTORY

The Company has one facility containing gas in underground storage. The current portion of the gas is classified in inventory and carried at the lower of cost or market. The non-current portion of the gas is classified in property and equipment and carried at cost. The carrying value of the non-current gas is evaluated for recoverability when either events or changes in circumstances indicate that it may not be recoverable. Withdrawals of current gas in underground storage are accounted for by utilizing a weighted average cost method whereby gas withdrawn from storage is relieved at the weighted average cost of current gas remaining in the facility.

The Company's current portion of natural gas inventory at September 30, 2009 is $12.3 million compared to $24.1 million at December 31, 2008. The Company recorded a non-cash impairment charge of $4.3 million for the three months ended March 31, 2009 to reduce the current portion of the Company's natural gas inventory to the lower of cost or market as a result of low commodity prices at March 31, 2009. No impairment charges were recognized for the three months ended September 30, 2009. The non-cash charge for the three months ended March 31, 2009 is reflected as a reduction to other operating revenues in the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2009.

Also included in current inventory at September 30, 2009 and December 31, 2008, are $18.0 million and $26.3 million, respectively, of tubulars and other equipment used in the Company's E&P segment. Tubulars and other equipment used by the Company's segments are carried at the lower of cost or market and are accounted for by utilizing a moving weighted average cost method that is applied within specific classes of inventory items. Purchases of inventory are recorded at cost and inventory is relieved at the weighted average cost of items remaining within a specified inventory class.

Other assets include $36.5 million at September 30, 2009, and $43.8 million at December 31, 2008, of inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale play.

(15) NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

In December 2008, the FASB issued certain provisions of FASB ASC 715-20, "Defined Benefit Plans – Overall," which require enhanced disclosures about the fair value measurements of employers' plan assets in the Company's year ending 2009 consolidated financial statements. These required disclosures include: (a) investment policies and strategies; (b) major categories of plan assets; (c) information about valuation techniques and inputs to those techniques, including the fair value hierarchy classifications of the major categories of plan assets; (d) the effects of fair value measurements using significant unobservable inputs on changes in plan assets; and (e) significant concentrations of risk within plan assets. The disclosures are not expected to have a material impact on the Company's consolidated financial statements.

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company is providing unaudited 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.

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 unaudited 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)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Three months ended September 30, 2009:					
Operating revenues	$ —	$ 485,382	$ 49,191	$ (31,624)	$ 502,949
Operating costs and expenses:					
Gas purchases	—	113,197	—	(241)	112,956
Operating expenses	—	51,385	18,784	(31,271)	38,898
General and administrative expenses	—	28,740	3,314	(112)	31,942
Depreciation, depletion and amortization	—	108,502	5,331	—	113,833
Taxes, other than income taxes	—	7,457	825	—	8,282
Total operating costs and expenses	—	309,281	28,254	(31,624)	305,911
Operating income	—	176,101	20,937	—	197,038
Other income	—	540	14	—	554
Equity in earnings of subsidiaries	118,254	—	—	(118,254)	—
Interest expense	—	3,070	2,207	—	5,277
Income (loss) before income taxes	118,254	173,571	18,744	(118,254)	192,315
Provision for income taxes	—	67,073	7,032	—	74,105
Net income (loss)	118,254	106,498	11,712	(118,254)	118,210
Less: Net (loss) attributable to noncontrolling interest	—	(44)	—	—	(44)
Net income (loss) attributable to Southwestern Energy	$ 118,254	$ 106,542	$ 11,712	$ (118,254)	$ 118,254

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Three months ended September 30, 2008:					
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 (loss) before income taxes	239,928	282,230	12,586	(182,664)	352,080
Provision for income taxes	21,760	107,172	4,783	—	133,715
Net income (loss)	218,168	175,058	7,803	(182,664)	218,365
Less: Net income attributable to noncontrolling interest	—	197	—	—	197
Net income (loss) attributable to Southwestern Energy	$ 218,168	$ 174,861	$ 7,803	$ (182,664)	$ 218,168

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Nine months ended September 30, 2009:					
Operating revenues	$ —	$ 1,470,647	$ 141,507	$ (90,868)	$ 1,521,286
Operating costs and expenses:					
Gas purchases	—	354,129	—	(806)	353,323
Operating expenses	—	139,101	47,201	(89,726)	96,576
General and administrative expenses	—	75,689	9,498	(336)	84,851
Depreciation, depletion and amortization	—	340,846	15,142	—	355,988
Impairment of natural gas and oil properties	—	907,812	—	—	907,812
Taxes, other than income taxes	—	21,598	2,365	—	23,963
Total operating costs and expenses	—	1,839,175	74,206	(90,868)	1,822,513
Operating income (loss)	—	(368,528)	67,301	—	(301,227)
Other income	—	1,066	22	—	1,088
Equity in earnings of subsidiaries	(193,476)	—	—	193,476	—
Interest expense	—	8,424	3,603	—	12,027
Income (loss) before income taxes	(193,476)	(375,886)	63,720	193,476	(312,166)
Provision (benefit) for income taxes	—	(142,795)	24,213	—	(118,582)
Net income (loss)	(193,476)	(233,091)	39,507	193,476	(193,584)
Less: Net (loss) attributable to noncontrolling interest	—	(108)	—	—	(108)
Net income (loss) attributable to Southwestern Energy	$ (193,476)	$ (232,983)	$ 39,507	$ 193,476	$ (193,476)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Nine months ended September 30, 2008:					
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 (loss) before income taxes	485,507	650,355	40,907	(428,243)	748,526
Provision for income taxes	21,760	246,927	15,545	—	284,232
Net income (loss)	463,747	403,428	25,362	(428,243)	464,294
Less: Net income attributable to noncontrolling interest	—	547	—	—	547
Net income (loss) attributable to Southwestern Energy	$ 463,747	$ 402,881	$ 25,362	$ (428,243)	$ 463,747

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
			(in thousands)		
September 30, 2009:					
ASSETS					
Cash and cash equivalents	$ 9,580	$ —	$ 79	$ —	$ 9,659
Accounts receivable	646	184,944	13,421	—	199,011
Inventories	—	29,380	929	—	30,309
Other	3,561	290,148	1,148	—	294,857
Total current assets	13,787	504,472	15,577	—	533,836
Intercompany receivables	1,683,361	(1,206,525)	(469,208)	(7,628)	—
Investments	—	10,566	(10,565)	(1)	—
Property and equipment	66,442	6,025,730	617,420	—	6,709,592
Accumulated depreciation, depletion and amortization	(36,146)	(2,792,245)	(53,959)	—	(2,882,350)
Net property and equipment	30,296	3,233,485	563,461	—	3,827,242
Investments in subsidiaries (equity method)	1,514,736	—	—	(1,514,736)	—
Other assets	17,803	35,557	43,705	—	97,065
Total assets	$ 3,259,983	$ 2,577,555	$ 142,970	$ (1,522,365)	$ 4,458,143
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 116,671	$ 250,582	$ 21,188	$ (7,629)	$ 380,812
Other current liabilities	1,980	173,822	4,902	—	180,704
Total current liabilities	118,651	424,404	26,090	(7,629)	561,516
Long-term debt	958,300	—	—	—	958,300
Other liabilities	34,809	36,379	4,684	—	75,872
Commitments and contingencies					
Deferred income taxes	(81,342)	678,334	35,898	—	632,890
Total liabilities	1,030,418	1,139,117	66,672	(7,629)	2,228,578
Total equity	2,229,565	1,438,438	76,298	(1,514,736)	2,229,565
Total liabilities and equity	$ 3,259,983	$ 2,577,555	$ 142,970	$ (1,522,365)	$ 4,458,143

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2008:					
ASSETS					
Cash and cash equivalents	$ 195,969	$ —	$ 308	$ —	$ 196,277
Accounts receivable	404	250,687	3,466	—	254,557
Inventories	—	49,579	798	—	50,377
Other	3,835	377,455	762	—	382,052
Total current assets	200,208	677,721	5,334	—	883,263
Intercompany receivables	1,252,573	(896,577)	(347,293)	(8,703)	—
Investments	—	10,309	(10,308)	(1)	—
Property and equipment	57,438	4,844,970	426,506	—	5,328,914
Accumulated depreciation, depletion and amortization	(30,679)	(1,548,927)	(35,701)	—	(1,615,307)
Net property and equipment	26,759	3,296,043	390,805	—	3,713,607
Investments in subsidiaries (equity method)	1,822,057	—	—	(1,822,057)	—
Other assets	19,985	99,547	43,756	—	163,288
Total assets	$ 3,321,582	$ 3,187,043	$ 82,294	$ (1,830,761)	$ 4,760,158
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 234,068	$ 325,057	$ 15,184	$ (8,704)	$ 565,605
Other current liabilities	1,810	210,087	2,811	—	214,708
Total current liabilities	235,878	535,144	17,995	(8,704)	780,313
Long-term debt	674,200	—	—	—	674,200
Other liabilities	32,882	27,899	5,194	—	65,975
Commitments and contingencies					
Deferred income taxes	(139,341)	845,593	15,455	—	721,707
Total liabilities	803,619	1,408,636	38,644	(8,704)	2,242,195
Total equity	2,517,963	1,778,407	43,650	(1,822,057)	2,517,963
Total liabilities and equity	$ 3,321,582	$ 3,187,043	$ 82,294	$ (1,830,761)	$ 4,760,158

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent	Guarantors	Non-Guarantors (in thousands)	Eliminations	Consolidated
Nine months ended September 30, 2009:					
Net cash provided by operating activities	$ 32,924	$ 896,046	$ 60,556	$ —	$ 989,526
Investing activities:					
Capital investments	(10,462)	(1,170,985)	(192,600)	—	(1,374,047)
Other	5,466	(21,101)	11,050	—	(4,585)
Net cash used in investing activities	(4,996)	(1,192,086)	(181,550)	—	(1,378,632)
Financing activities:					
Intercompany activities	(416,805)	296,040	120,765	—	—
Payments on short-term debt	(60,600)	—	—	—	(60,600)
Payments on revolving long-term debt	(879,400)	—	—	—	(879,400)
Borrowings under revolving long-term debt	1,164,100	—	—	—	1,164,100
Change in bank drafts outstanding	(25,783)	—	—	—	(25,783)
Proceeds from exercise of common stock options	4,171	—	—	—	4,171
Net cash provided by (used in) financing activities	(214,317)	296,040	120,765	—	202,488
Increase (decrease) in cash and cash equivalents	(186,389)	—	(229)	—	(186,618)
Cash and cash equivalents at beginning of year	195,969	—	308	—	196,277
Cash and cash equivalents at end of period	$ 9,580	$ —	$ 79	$ —	$ 9,659
Nine months ended September 30, 2008:					
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	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	455,417	(529,047)	73,630	—	—
Payments on short-term debt	(600)	—	—	—	(600)
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
Debt issuance costs and revolving credit facility costs	(8,895)	—	—	—	(8,895)
Excess tax benefit for stock-based compensation	42,197	—	—	—	42,197
Change in bank drafts outstanding	5,402	—	—	—	5,402
Proceeds from exercise of common stock options	3,240	—	—	—	3,240
Net cash provided by (used in) financing activities	254,561	(529,047)	73,630	—	(200,856)
Increase (decrease) in cash and cash equivalents	425,066	—	(710)	—	424,356
Cash and cash equivalents at beginning of year	433	—	1,399 (1)	—	1,832
Cash and cash equivalents at end of period	$ 425,499	$ —	$ 689	$ —	$ 426,188

(1) Cash and cash equivalents at the beginning of the year for 2008 $1.1 million classified as “held for sale.” See Note 4 for additional information.

(17) SUBSEQUENT EVENTS

The Company evaluates subsequent events through the date the financial statements are issued, which for the quarterly period ended September 30, 2009, is October 29, 2009. No additional subsequent events requiring disclosure were identified by the Company.

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 2008 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, 2009 and 2008. For definitions of commonly used natural gas and oil terms used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2008 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 2008 Annual Report on Form 10-K, and Item 1A, "Risk Factors" in Part II in this Form 10-Q and any other Form 10-Q filed during the fiscal year. You should read the following discussion with our unaudited condensed consolidated financial statements and the related notes included in this Form 10-Q.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily engaged in natural gas and crude oil exploration, development and production ("E&P") within the United States. We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses ("Midstream Services"). We have historically operated principally in three segments: 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, no longer have any natural gas distribution operations. The operating results and cash flows from AWG through June 30, 2008 are included in the unaudited condensed consolidated statements of operations and statements of cash flows, as applicable, and are not presented as "discontinued operations." We refer you to Note 4 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional information.

We derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. 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. 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 in turn determines the sale prices for our production. 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 counterparties in our hedging activities. 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 counterparty losses 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.

As a result of the ongoing development of our Fayetteville Shale play and our improving well performance, we have experienced over 50% growth in our production volumes in the first nine months of 2009 as compared with the prior year. However, the increase in our revenues resulting from our production growth was more than offset by significantly lower realized prices for natural gas over the same period. We expect our production growth over 2008, as discussed in more detail in our guidance below, to continue for the remainder of the year. We rely in part upon the Fayetteville and Greenville Laterals built by Texas Gas Transmission, LLC ("Texas Gas"), a subsidiary of Boardwalk Pipeline Partners, LP, to service our increased production from the Fayetteville Shale play. We curtailed a portion of our natural gas production during the third quarter of 2009 as a result of inspections, repairs and maintenance relating to the remediation of pipe anomalies on the Fayetteville and Greenville Lateral. The remediation of the pipe anomalies by Texas Gas was pursuant to an agreement with Pipeline and Hazardous Materials Safety Administration ("PHMSA") entered during the second quarter 2009, which defined the testing protocol and remediation efforts that Texas Gas would need to complete in order to return to normal operating pressures, and for the Fayetteville Lateral, to operate at higher than normal operating pressures. The testing protocol and remediation efforts include replacement of certain pipe joints, performing investigative digs to physically inspect the pipe sections and conducting metallurgical testing and analysis on a variety of pipe samples. On October 8, 2009, Texas Gas announced it received authorization from the PHMSA to operate the Fayetteville and Greenville Laterals at standard operating pressures with a capacity of 805,000 MMBtu per day. Texas Gas is continuing to perform the testing protocol required by PHMSA and, once that testing has been completed and the results known, expects to request from PHMSA the authority to operate the Fayetteville Lateral at higher than normal operating pressures under a special permit. In addition, Texas Gas plans to add compression in 2010 that will increase peak-day delivery capacities to approximately 1.0 Bcf per day on the Greenville Lateral, and assuming that the authority is received to operate the Fayetteville Lateral at higher than normal operating pressures, increase peak-day delivery capacities to approximately 1.3 Bcf per day on the Fayetteville Lateral. The compression for the Fayetteville and Greenville Laterals has been approved by FERC. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate a pipeline at higher than normal operating pressures. We cannot predict when or if the Fayetteville Lateral will be able to operate at higher capacities. In addition, PHMSA mandated repairs in conjunction with obtaining the special operating permit or any other substantial delay in obtaining the special operating permit from PHMSA could result in future curtailments of our capacity.

Three Months Ended September 30, 2009 Compared with Three Months Ended September 30, 2008

Our natural gas and oil production increased to 73.2 Bcfe for the three months ended September 30, 2009, up 38% from the three months ended September 30, 2008. The 20.3 Bcfe increase in 2009 production was primarily due to a 21.6 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program. The average price realized for our gas production, including the effects of hedges, decreased approximately 41% to $5.06 per Mcf for the three months ended September 30, 2009, as compared to the same period in 2008.

We reported net income attributable to Southwestern Energy of $118.3 million for the three months ended September 30, 2009, or $0.34 per diluted share, down from $218.2 million, or $0.63 per diluted share, for the comparable period in 2008. Our operating results for the three months ended September 30, 2008 include a $57.3 million pre-tax gain related to the sale of AWG in the third quarter of 2008.

Our E&P segment reported operating income of $172.0 million for the three months ended September 30, 2009, down $108.6 million from the comparable period of 2008, primarily due to the effects of significantly lower gas and oil prices which decreased revenues by $257.6 million and an increase in operating costs and expenses of $21.4 million relating to our increased gas production which more than offset the higher revenues of $170.4 million realized from increased gas production volumes. Operating income for our Midstream Services segment was $25.1 million for the three months ended September 30, 2009, up from $18.3 million for the three months ended September 30, 2008, due to an increase of $15.1 million in gathering revenues and an increase of $0.9 million in the margin generated from our natural gas marketing activities, which were partially offset by a $9.2 million increase in operating costs and expenses, exclusive of gas purchase costs.

We had capital investments of $408.8 million for the three months ended September 30, 2009, of which $333.9 million was invested in our E&P segment compared to $471.6 million for the same period of 2008, of which $415.7 million was invested in our E&P segment.

Nine Months Ended September 30, 2009 Compared with Nine Months Ended September 30, 2008

For the nine months ended September 30, 2009, our gas and oil production increased to 211.4 Bcfe, up 54% compared to the same period in 2008. The 74.4 Bcfe increase in 2009 production was due to a 79.2 Bcf increase in net production from our Fayetteville Shale play, partially offset by decreases in net production resulting from the sale of all of our producing properties in the Permian Basin and Gulf Coast. The average price realized for our gas production, including the effects of hedges, decreased approximately 35% to $5.31 per Mcf for the nine months ended September 30, 2009, as compared to the same period last year.

We reported a net loss attributable to Southwestern Energy of $193.5 million for the nine months ended September 30, 2009, or $0.56 per diluted share, down from net income attributable to Southwestern Energy of $463.7 million, or $1.34 per diluted share, for the comparable period in 2008. The loss includes the recognition of a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties recorded during the three months ended March 31, 2009. The ceiling test impairment was recognized as a result of a significant decline in natural gas prices. Our operating results for the nine months ended September 30, 2008 include a $57.3 million pre-tax gain related to the sale of AWG in the third quarter of 2008.

Our E&P segment reported an operating loss of $381.4 million for the nine months ended September 30, 2009, down $1,042.8 million from the comparable period of 2008, due to the $907.8 million non-cash ceiling test impairment of our natural gas and oil properties, decreased prices realized from the sale of our production, and an increase in operating costs and expenses of $108.9 million relating to our increased gas production all of which more than offset the higher revenues of $593.5 million realized from increased gas production volumes. Operating income for our Midstream Services segment was $80.3 million for the nine months ended September 30, 2009, up from $43.4 million for the nine months ended September 30, 2008, due to a $59.7 million increase in gathering revenues and a $4.6 million increase in the margin generated from our natural gas marketing activities, which were partially offset by a $27.5 million increase in operating costs and expenses, exclusive of gas purchase costs. Our Natural Gas Distribution segment, which was sold as of July 1, 2008, had operating income of $10.7 million as of the sale date that is included in our results for the nine months ended September 30, 2008.

We had capital investments of $1,368.2 million for the nine months ended September 30, 2009, of which $1,186.4 million was invested in our E&P segment compared to $1,297.0 million for the same period of 2008, of which $1,155.0 million was invested in our E&P segment.

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense, interest income, income tax expense, pension expense and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
Revenues (in thousands)	$ 371,034	$ 458,173	$ 1,121,800	$ 1,147,915
Impairment of natural gas and oil properties (in thousands)	$ —	$ —	$ 907,812	$ —
Operating costs and expenses (in thousands)	$ 198,996	$ 177,566	$ 595,410	$ 486,512
Operating income (loss) (in thousands)	$ 172,038	$ 280,607	$ (381,422)	$ 661,403
Gas production (MMcf)	72,982	52,375	210,791	134,892
Oil production (MBbls)	29	76	95	345
Total production (MMcfe)	73,150	52,832	211,358	136,964
Average gas price per Mcf, including hedges	$ 5.06	$ 8.56	$ 5.31	$ 8.19
Average gas price per Mcf, excluding hedges	$ 2.85	$ 8.82	$ 3.16	$ 8.83
Average oil price per Bbl	$ 64.20	$ 125.33	$ 49.47	$ 112.37
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.76	$ 0.96	$ 0.76	$ 0.90
General & administrative expenses	$ 0.38	$ 0.33	$ 0.34	$ 0.38
Taxes, other than income taxes	$ 0.10	$ 0.15	$ 0.10	$ 0.15
Full cost pool amortization	$ 1.43	$ 1.86	$ 1.56	$ 2.03

Revenues

Revenues for our E&P segment were down $87.1 million, or 19%, for the three months ended September 30, 2009 compared to the same period in 2008. Lower natural gas and oil prices in the third quarter of 2009 decreased revenues by $257.6 million, which were partially offset by a $170.4 million increase in revenue attributable to increased production volumes. E&P revenues were down $26.1 million, or 2%, for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008. This decrease was due to the negative $614.2 million impact of lower realized natural gas and oil prices, a $4.3 million non-cash impairment of our natural gas inventory and $1.1 million from other declines in our revenue which were partially offset by a $593.5 million increase attributable to increased production volumes. We expect our production volumes to continue to increase due to the development of our

Fayetteville Shale play in Arkansas. Natural gas and oil prices are difficult to predict and subject to wide price fluctuations. As of October 27, 2009, we had hedged 33.0 Bcf of our remaining 2009 gas production, 50.0 Bcf of 2010 gas production and 30.0 Bcf of 2011 gas production to limit our exposure to price fluctuations. We refer you to Note 6 to the unaudited condensed consolidated financial statements included in this Form 10-Q and to the discussion of "Commodity Prices" provided below for additional information.

Production

Natural gas and oil production for the three months ended September 30, 2009 was up approximately 38%, from the comparable period in 2008, to 73.2 Bcfe, due to a 21.6 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program. Gas production represented nearly 100% of our total gas and oil equivalent production for the three months ended September 30, 2009 and was up approximately 39% to 73.0 Bcf compared to the same period in 2008. Net production from the Fayetteville Shale was 58.8 Bcf for the three months ended September 30, 2009 compared to 37.2 Bcf for the same period in 2008. Natural gas and oil production for the nine months ended September 30, 2009 was up approximately 54%, from the comparable period in 2008, to 211.4 Bcfe, due to a 79.2 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program, which was partially offset by a decrease of 3.1 Bcfe in net production resulting from the sale of all of our producing properties in the Permian Basin and Gulf Coast. Gas production represented nearly 100% of our total gas and oil equivalent production for the nine months ended September 30, 2009 and was up approximately 56% to 210.8 Bcf compared to the same period in 2008. Net production from the Fayetteville Shale was 169.6 Bcf for the nine months ended September 30, 2009 compared to 90.4 Bcf for the same period in 2008.

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.

We rely in part upon the Fayetteville and Greenville Laterals built by Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP, to service our increased production from the Fayetteville Shale play. We curtailed a portion of our natural gas production during the third quarter of 2009 as a result of inspections, repairs and maintenance relating to the remediation of pipe anomalies on the Fayetteville and Greenville Lateral. The remediation of the pipe anomalies by Texas Gas was pursuant to an agreement with PHMSA entered during the second quarter 2009, which defined the testing protocol and remediation efforts that Texas Gas would need to complete in order to return to normal operating pressures, and for the Fayetteville Lateral, to operate at higher than normal operating pressures. The testing protocol and remediation efforts include replacement of certain pipe joints, performing investigative digs to physically inspect the pipe sections and conducting metallurgical testing and analysis on a variety of pipe samples. On October 8, 2009, Texas Gas announced it received authorization from the PHMSA to operate the Fayetteville and Greenville Laterals at standard operating pressures with a capacity of 805,000 MMBtu per day. Texas Gas is continuing to perform the testing protocol required by PHMSA and, once that testing has been completed and the results known, expects to request from PHMSA the authority to operate the Fayetteville Lateral at higher than normal operating pressures under a special permit. In addition, Texas Gas plans to add compression in 2010 that will increase peak-day delivery capacities to approximately 1.0 Bcf per day on the Greenville Lateral, and assuming that the authority is received to operate the Fayetteville Lateral at higher than normal operating pressures, increase peak-day delivery capacities to approximately 1.3 Bcf per day on the Fayetteville Lateral. The compression for the Fayetteville and Greenville Laterals has been approved by FERC. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate a pipeline at higher than normal operating pressures. We cannot predict when or if the Fayetteville Lateral will be able to operate at higher capacities. In addition, PHMSA mandated repairs in conjunction with obtaining the special operating permit or any other substantial delay in obtaining the special operating permit from PHMSA could result in future curtailments of our capacity.

We have increased our natural gas and oil production guidance for the fourth quarter of 2009 to 86 to 89 Bcfe, up from 74 to 82 Bcfe. Our guidance for 2009 natural gas and oil production is now 297 to 300 Bcfe, which is an increase of approximately 53% over our actual natural gas and oil production for 2008 of 194.6 Bcfe. Of this total for 2009, approximately 243 to 245 Bcf is expected to come from the Fayetteville Shale play.

Commodity Prices

The average price realized for our gas production, including the effects of hedges, decreased approximately 41% to $5.06 per Mcf for the three months ended September 30, 2009, and decreased 35% to $5.31 per Mcf for the nine months ended September 30, 2009, as compared to the same periods in 2008. The change in the average price realized reflects changes in average spot market prices and the effects of our price hedging activities. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 3 and Note 6 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion).

Our hedging activities increased the average gas price $2.21 per Mcf for the three months ended September 30, 2009 compared to a decrease of $0.26 per Mcf for the same period in 2008. Our hedging activities increased the average gas price $2.15 per Mcf for the nine months ended September 30, 2009 compared to a decrease of $0.64 per Mcf for the same period in 2008. We had protected approximately 65% of our gas production for the nine months ended September 30, 2009 from the impact of widening basis differentials through our hedging activities and sales arrangements. Additionally, as of October 27, 2009, we have protected basis on approximately 50 Bcf of our remaining 2009 expected gas production through hedging activities and sales arrangements at a basis differential to NYMEX gas prices of approximately $0.25 per Mcf, excluding transportation charges and fuel charges. Disregarding the impact of hedges, the average price received for our gas production for the nine months ended September 30, 2009 was approximately $0.77 lower than average NYMEX spot prices, which represented the average locational basis differential. We typically sell our natural gas at a discount to NYMEX spot prices as a result of locational basis differentials, transportation and fuel charges.

As of October 27, 2009, we had NYMEX fixed price hedges in place on notional volumes of 15.0 Bcf of our remaining 2009 gas production at an average price of $8.41 per MMBtu and collars in place on notional volumes of 18.0 Bcf of our remaining 2009 gas production at an average floor and ceiling price of $8.42 and $11.04 per MMBtu, respectively.

As of October 27, 2009, we had NYMEX fixed price hedges in place on notional volumes of 36.0 Bcf of our 2010 gas production and 30.0 Bcf of our 2011 gas production and collars in place on notional volumes of 14.0 Bcf of our 2010 gas production. Additionally, we have basis swaps on 22.1 Bcf for the remainder of 2009, 46.5 Bcf for 2010 and 9.0 Bcf for 2011, in order to reduce the effects of widening market differentials on prices we receive.

Operating Income

Operating income from our E&P segment was down 39% to $172.0 million for the three months ended September 30, 2009 compared to $280.6 million for the same period in 2008. The $108.6 million decrease in operating income was the result of a 19% decrease in revenues, as the revenue impact of the decline in gas prices more than offset the effect of the growth in our production volumes, and a 12% increase in operating costs and expenses. We recorded an operating loss from our E&P segment of $381.4 million for the nine months ended September 30, 2009, which represents a decline of $1,042.8 million, or 158%, from the same period in 2008. The $1,042.8 million decrease in operating income was the result of a $907.8 million non-cash ceiling test impairment recorded in the first quarter resulting from lower natural gas prices, an increase in other operating costs and expenses of $108.9 million, or 22%, resulting from our significant production growth and a net decrease in revenue of $26.1 million, or 2%, as the decline in gas prices more than offset the effect of the growth in our production volumes during the period.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.76 for the three months ended September 30, 2009 compared to $0.96 for the same period in 2008. Lease operating expenses per Mcfe for our E&P segment were also $0.76 for the nine months ended September 30, 2009 compared to $0.90 for the same period in 2008. The decreases primarily resulted from lower natural gas prices which decreased the cost of compressor fuel.

General and administrative expenses per Mcfe were $0.38 for the three months ended September 30, 2009, up from $0.33 for the same period in 2008 primarily due to a $5.4 million increase in accrued employee incentive compensation expense which was only partially offset by the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $27.6 million for the three months ended September 30, 2009 compared to $17.2 million for the same period in 2008. Payroll, employee incentive compensation, and other employee-related costs increased by $7.9 million as a result of the expansion of our E&P operations in the Fayetteville Shale play.

General and administrative expenses per Mcfe decreased 11% to $0.34 for the nine months ended September 30, 2009 compared to the same period in 2008, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $72.3 million for the nine months ended September 30, 2009 compared to $52.1 million for the same period in 2008. The increase was primarily due to a $14.8 million increase in payroll, employee incentive compensation and other employee-related costs associated with the expansion of our E&P operations in the Fayetteville Shale play.

Taxes other than income taxes per Mcfe decreased to $0.10 for the three and nine months ended September 30, 2009 compared to $0.15 for the same periods in 2008. 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. Effective January 1, 2009, the State of Arkansas increased the severance tax on natural gas wells, new discovery gas wells and gas wells that produce below a specified level. The new severance tax rates increase the severance taxes we pay with respect to all of our production within the State of Arkansas, including our Fayetteville Shale operations, and impacted our results of operations by increasing taxes other than income by $1.6 million or $0.02 per Mcfe for the three months ended September 30, 2009 compared to the same period in 2008, and by $7.3 million or $0.03 per Mcfe for the nine months ended September 30, 2009 compared to the same period in 2008.

Our full cost pool amortization rate averaged $1.43 per Mcfe for the three months ended September 30, 2009 compared to $1.86 per Mcfe for the same period in 2008. For the first nine months of 2009, our full cost pool amortization rate averaged $1.56 per Mcfe compared to $2.03 per Mcfe for the same period in 2008. The decline in the average amortization rate for the three months ended September 30, 2009 compared to the same period of 2008 was primarily the result of the $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009. The decline in the average amortization rate for the nine months ended September 30, 2009 compared to the same period of 2008 was the result of the impairment recorded in 2009 as well as sales of natural gas and oil properties in the second and third quarters of 2008, the proceeds of which were credited to the full cost pool. The amortization rate is impacted by the timing and the amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, impairments 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.

Unevaluated costs excluded from amortization were $624.4 million at September 30, 2009 compared to $540.6 million at December 31, 2008. The increase in unevaluated costs since December 31, 2008, resulted primarily from a $49.1 million increase in our undeveloped leasehold acreage and seismic costs (with $24.3 million of the increase related to our Fayetteville Shale play) and a $6.7 million increase in our drilling activity.

The timing and amount of production and reserve additions 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.

Midstream Services

	For the three months ended September 30,		For the nine months ended September 30,	
	2009	2008	2009	2008
	($ in thousands, except volumes)			
Revenues – marketing	$ 311,497	$ 649,521	$ 951,003	$ 1,648,126
Revenues – gathering	$ 48,714	$ 33,650	$ 139,846	$ 80,128
Gas purchases – marketing	$ 306,745	$ 645,701	$ 936,356	$ 1,638,127
Operating costs and expenses	$ 28,366	$ 19,216	$ 74,239	$ 46,710
Operating income	$ 25,100	$ 18,254	$ 80,254	$ 43,417
Gas volumes marketed (Bcf)	98.3	71.6	273.9	181.2
Gas volumes gathered (Bcf)	93.0	64.6	267.4	153.0

Revenues

Revenues from our marketing activities were down 52% to $311.5 million for the three months ended September 30, 2009 compared to the same period in 2008, and were down 42% to $951.0 million for the nine months ended September 30, 2009 compared to the same period in 2008. The decreases in marketing revenues for the three- and nine-month periods ended September 30, 2009 resulted from a decrease in the prices received for volumes marketed and were partially offset by increases in gas volumes marketed. For the three months ended September 30, 2009, the price received for volumes marketed decreased 65% compared to the same period in 2008 and decreased 62% for the nine months ended September 30, 2009 compared to the same period in 2008. For the three months ended September 30, 2009, the volumes marketed increased 37% and increased 51% for the nine months ended September 30, 2009 compared to the same periods in 2008.

Revenues from our gathering activities were up 45% to $48.7 million for the three months ended September 30, 2009 compared to the same period in 2008, and were up 75% to $139.8 million for the nine months ended September 30, 2009 compared to the same period in 2008. The increase in gathering revenues for the three- and nine-month periods ended September 30, 2009 compared to the same periods in 2008 resulted from an increase in the gas volumes gathered. For the three months ended September 30, 2009, the volumes gathered increased 44% compared to the same period in 2008 and increased 75% for the nine months ended September 30, 2009 compared to the same period in 2008.

Of the total volumes marketed, production from our E&P operated wells accounted for 84% and 96% of the marketed volumes for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009, production from our E&P operated wells accounted for 90% and 95% of the marketed volumes, respectively. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Substantially all of the increase in gathering revenues for the three months ended September 30, 2009 and for the nine months ended September 30, 2009, resulted from increases in volumes gathered related to the Fayetteville Shale play. 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 $6.8 million to $25.1 million for the three months ended September 30, 2009 compared to $18.3 million for the same period in 2008, and increased $36.8 million to $80.3 million for the nine months ended September 30, 2009 compared to $43.4 million for the same period in 2008. The increases in operating income primarily reflect the substantial increase in gas volumes marketed and gathered. The $6.8 million increase in operating income for three months ended September 30, 2009 was primarily due to a $15.1 million increase in gathering revenues and was partially offset by an increase in operating costs and expenses of $9.2 million. The $36.8 million increase in operating income for the nine months ended September 30, 2009 was primarily due to a $59.7 million increase in gathering revenues and was partially offset by an increase in operating costs and expenses of $27.5 million. The remaining changes in operating income were due to an increase of $0.9 million in the margin generated by our gas marketing activities for the three months ended September 30, 2009 and an increase in the margin of $4.6 million for the nine months ended September 30, 2009. Margins may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increases in volumes marketed and gathered for the three- and nine-month periods ended September 30, 2009, as compared to the same periods in 2008, primarily resulted from our increased E&P production volumes. 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” included in this Form 10-Q for additional information.

Natural Gas Distribution

Effective July 1, 2008, we sold all of the capital stock of AWG for $223.5 million (net of expenses related to the sale). In order to receive regulatory approval for the sale and certain related transactions, we paid $9.8 million to AWG for the benefit of its customers. A gain on the sale of $57.3 million ($35.4 million after-tax) was recorded 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 of $10.7 million through the sale date that is included in our results for the nine months ended September 30, 2008.

Interest Expense and Interest Income

Interest costs, net of capitalization, decreased to $5.3 million and $12.0 million for the three- and nine-month periods ended September 30, 2009, respectively, compared to $6.6 million and $27.1 million for the same periods in 2008. The decreases were primarily due to increased capitalized interest and a decline in our weighted average interest rate. We capitalized interest of $9.2 million and $31.9 million for the three- and nine-month periods ended September 30, 2009, respectively, compared to $8.1 million and $21.6 million for the same periods in 2008. Interest income for the three month period ended September 30, 2009 was less than $0.1 million compared to $2.3 million for the same period in 2008. Interest income for the nine-month period ended September 30, 2009 was $0.4 million compared to $2.6 million for the same period in 2008. Interest income is recorded in other income in the unaudited condensed consolidated statements of operations.

Income Taxes

Our effective tax rate was 38.0% for the nine months ended September 30, 2009 and 2008. For the nine months ended September 30, 2009, we recorded an income tax benefit of $118.6 million compared to an income tax expense of $284.2 million for the same period in 2008 primarily as a result of the $907.8 million non-cash impairment of our gas and oil properties. We do not expect to be subject to current income taxes in 2009.

Pension Expense

We incurred pension costs of $1.8 million for the three months ended September 30, 2009 for our pension and other postretirement benefit plans compared to $1.3 million for the same period in 2008. For the nine months ended September 30, 2009, our pension costs were $5.5 million compared to $5.2 million for the same period in 2008. Contributing to the increased pension expense were higher pension costs resulting from increases in average employee headcount.

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 $9.0 million to our pension plans and less than $0.1 million to our other postretirement benefit plans in 2009. As of September 30, 2009, $7.4 million has been contributed to the pension plans and less than $0.1 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 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Stock-Based Compensation

We recognized expense of $2.4 million and capitalized $1.4 million to the full cost pool for stock-based compensation for the three months ended September 30, 2009 compared to $1.8 million expensed and $1.4 million capitalized to the full cost pool for the comparable period in 2008. We recognized expense of $6.9 million and capitalized $4.3 million to the full cost pool for stock-based compensation for the nine months ended September 30, 2009 compared to $5.0 million expensed and $3.2 million capitalized to the full cost pool for the comparable period in 2008. We refer you to Note 12 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

Adoption of Accounting Principles

In June 2009, we implemented the Financial Accounting Standards Board Accounting Standards Codification. The implementation establishes the FASB ASC as the source of authoritative accounting principles in the preparation of financial statements in conformity with GAAP. The FASB ASC does not change GAAP and its implementation did not have a material impact on our consolidated financial statements.

On January 1, 2009, we implemented certain provisions of FASB ASC Topic 810-10, “Consolidation – Overall,” which establish accounting and reporting standards for (1) ownership interests in subsidiaries held by others, (2) the amount of consolidated net income attributable to the controlling and noncontrolling interests, (3) changes in the controlling ownership interest, (4) the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated and (5) disclosures that clearly identify and distinguish between the interests of the controlling and noncontrolling owners. The implementation resulted in changes to our presentation for noncontrolling interests and did not have a material impact on our results of operations and financial condition.

On January 1, 2009, we implemented certain provisions of FASB ASC Topic 815-10, “Derivatives and Hedging – Overall,” which require enhanced disclosure about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for and (3) how derivative instruments and related hedged items affect our financial position, financial performance and cash flows. The implementation did not have a material impact on our Company's results of operations and financial condition.

On January 1, 2009, we implemented certain provisions of FASB ASC Topic 820-10, "Fair Value Measurements and Disclosures – Overall," which require the fair value application 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). The implementation did not have a material impact on our results of operations and financial condition.

On June 30, 2009, we implemented certain provisions of FASB ASC Topic 825-10, "Financial Instruments – Overall," which require that the (1) fair value disclosures required for certain financial instruments be included in interim financial statements and (2) public companies disclose the method and significant assumptions used to estimate the fair value of those financial instruments and to discuss any changes of method or assumptions, if any, during the reporting period. The implementation did not have a material impact on our Company's results of operations and financial condition.

On June 30, 2009, we implemented certain provisions of FASB ASC Topic 855-10, "Subsequent Events – Overall," which establish the general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Among other things, we are now required to disclose the date through which we have evaluated subsequent events and the basis for that date. The implementation did not have a material impact on our results of operations and financial condition.

In December 2008, the FASB issued certain provisions of FASB ASC 715-20, "Defined Benefit Plans – Overall," which require enhanced disclosures about the fair value measurements of employers' plan assets in our year ending 2009 consolidated financial statements. These required disclosures include: (a) investment policies and strategies; (b) major categories of plan assets; (c) information about valuation techniques and inputs to those techniques, including the fair value hierarchy classifications of the major categories of plan assets; (d) the effects of fair value measurements using significant unobservable inputs on changes in plan assets; and (e) significant concentrations of risk within plan assets. The disclosures are not expected to have a material impact on our consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our Credit Facility (we refer you to Note 5 to the unaudited condensed consolidated financial statements included in this Form 10-Q and the section below under "Financing Requirements" for additional discussion of our Credit Facility) and funds accessed through debt and equity markets as our primary sources of liquidity. We may borrow up to $1.0 billion under our Credit Facility from time to time. The amount available under our 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, 2009, we had borrowings of $284.7 million under our Credit Facility compared to no borrowings at December 31, 2008.

In the second quarter of 2009, substantially all of the 7.625% Senior Notes were put to us by the note holders and resulted in the payment of approximately $62.1 million in principal and accrued interest on May 1, 2009. We utilized funds available under the Credit Facility to pay the note holders.

Net cash provided by operating activities increased 2% to $989.5 million for the nine months ended September 30, 2009 compared to $966.7 million for the same period in 2008, due to an increase in net income adjusted for non-cash expenses and changes in working capital accounts. For the nine months ended September 30, 2009, requirements for our capital investments were funded from our cash and cash equivalents available at December 31, 2008, cash generated from our operating activities, and borrowings under our Credit Facility.

At September 30, 2009, our capital structure consisted of 30% debt and 70% equity. We believe that our operating cash flow and the available funds under our Credit Facility will be adequate to meet our anticipated capital and operating requirements for 2009. The credit status of the financial institutions participating in our Credit Facility could adversely impact our ability to borrow funds under the Credit Facility. While we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each lender will be able to meet its obligation.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our natural 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 Note 6 in the unaudited condensed consolidated financial statements included 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 depend 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 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 $1.4 billion for the nine months ended September 30, 2009 compared to $1.3 billion for the same period in 2008. Our E&P segment investments were $1.2 billion for both the nine months ended September 30, 2009 and 2008. Our E&P segment capitalized internal costs of $77.3 million for the nine months ended September 30, 2009 compared to $60.7 million for the comparable period in 2008. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties. The increases in internal costs capitalized since 2008 have resulted from the addition of personnel and related costs in our exploration and development segment.

Although the remainder of our 2009 capital investment program is expected to be funded through cash and cash equivalents available at September 30, 2009, cash flow from operations and borrowings from our Credit Facility, we may adjust the level of our 2009 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 $959.5 million at September 30, 2009 compared to $735.4 million at December 31, 2008. Our Credit Facility has a borrowing capacity of $1.0 billion, which may be increased up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of September 30, 2009, we had borrowings of $284.7 million under our Credit Facility with a weighted average interest rate of 1.126% compared to no borrowings at December 31, 2008. The interest rate on the Credit Facility is calculated based upon our public debt rating and is currently 87.5 basis points over LIBOR. 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 Credit Facility contains covenants which impose certain restrictions on us. Under the Credit Facility, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of 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. Our Credit Facility's financial covenants with respect to capitalization percentages exclude the noncontrolling interest in equity, the effects of non-cash entries that result from any full cost ceiling impairments, hedging activities and our pension and other postretirement liabilities. Therefore, under our Credit Facility our capital structure at September 30, 2009 would have been 27% debt and 73% equity. We were also in compliance with all of the other covenants of the Credit Facility at September 30, 2009. 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.

At September 30, 2009, our capital structure consisted of 30% debt and 70% equity. Our debt as a percentage of capital increased during the nine months ended September 30, 2009 primarily due to our increased debt levels and our net loss of $193.5 million and other changes in equity for the nine months ended September 30, 2009. Equity at

September 30, 2009 also includes an accumulated other comprehensive gain of $147.6 million related to our hedging activities and a loss of $10.6 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on current market values of our hedges at September 30, 2009 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.

As part of our strategy to ensure a certain level of cash flow to fund our operations, at October 27, 2009 we have hedged 33.0 Bcf of our remaining 2009 gas production, 50.0 Bcf of our expected 2010 gas production and 30.0 Bcf of our expected 2011 gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans. If commodity prices remain near their current prices, we may decrease and/or reallocate our planned capital investments.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. There have been no material changes to our contractual obligations from those disclosed in our 2008 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. We currently expect to contribute approximately $9.0 million to our pension plans and less than $0.1 million to our postretirement benefit plans in 2009. As of September 30, 2009, we have contributed $7.4 million to our pension plans and have contributed less than $0.1 million to our postretirement benefit plans. At September 30, 2009, we recognized a liability of $12.6 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $15.4 million at December 31, 2008. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 13 in the unaudited condensed consolidated financial statements included 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 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 Credit Facility described above. We had negative working capital of $27.7 million at September 30, 2009, and positive working capital of $103.0 million at December 31, 2008. Current assets decreased $349.4 million at September 30, 2009 compared to current assets at December 31, 2008, due to a $195.0 million decrease in cash equivalents, a $113.0 million decrease in our current hedging asset and a $55.5 million decrease in accounts receivable. Current liabilities decreased $218.8 million as a result of a $103.1 million decrease in accounts payable, a $60.0 million decrease in short-term debt as substantially all of the 7.625% Senior Notes were put to us by the note holders which resulted in a payment of approximately $62.1 million in principal and accrued interest on May 1, 2009, and a $41.4 million decrease in our current deferred income taxes related to our hedging activities.

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. We recorded a $4.3 million non-cash natural gas inventory impairment charge for the three months ended March 31, 2009 to reduce the current portion of our natural gas inventory to the lower of cost or market. The gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments, especially during periods of colder weather. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in additional write-downs of our gas in underground 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 11% of accounts receivable at September 30, 2009. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At September 30, 2009, we had $959.5 million of total debt with an average interest rate of 5.58%. Our revolving credit facility has a floating interest rate (1.126% at September 30, 2009). At September 30, 2009, we had $284.7 million of borrowings outstanding under our Credit Facility. Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. We do not currently have any interest rate swaps in effect.

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 counterparty losses 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, 2009, the fair value of our financial instruments related to natural gas production was a $234.9 million asset.

	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, 2009 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2009	15.0	8.41	—	—	—	54.9
2010	36.0	9.04	—	—	—	101.2
2011	20.0	6.53	—	—	—	(6.7)
Costless Collars:						
2009	18.0	—	8.42	11.04	—	66.2
2010	14.0	—	8.29	10.57	—	32.3
Basis Swaps:						
2009	22.1	—	—	—	(0.41)	(4.7)
2010	46.5	—	—	—	(0.37)	(7.3)
2011	9.0	—	—	—	(0.35)	(1.0)

At September 30, 2009, our basis swaps 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, 2009, we recorded an unrealized loss of $14.7 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized gain of $8.2 million related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

At December 31, 2008, we had outstanding natural gas price swaps on total notional volumes of 77.3 Bcf in 2009 and 36.0 Bcf in 2010 for which we will receive fixed prices ranging from $7.29 to $14.27 per MMBtu. At December 31, 2008, we had outstanding fixed price basis differential swaps on 50.0 Bcf of 2009, 32.0 Bcf of 2010 and 7.2 Bcf of 2011 gas production that did not qualify for hedge treatment.

At December 31, 2008, we had collars in place on notional volumes of 59.0 Bcf in 2009 and 14.0 Bcf in 2010. The 59.0 Bcf in 2009 had an average floor and ceiling price of $8.71 and $11.69 per MMBtu, respectively. The 14.0 Bcf in 2010 had an average floor and ceiling price of $8.29 and $10.57 per MMBtu, respectively.

Midstream Services

At September 30, 2009, our Midstream Services segment had outstanding fair value hedges in place on 0.1 Bcf, 0.3 Bcf, 0.1 Bcf and 0.1 Bcf of gas for 2009, 2010, 2011 and 2012, respectively. These hedges are a mixture of floating-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from October 2009 through March 2012 and have a net fair value liability of $1.0 million as of September 30, 2009.

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, 2009. There were no changes in our internal control over financial reporting during the three months ended September 30, 2009 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 2008 Annual Report on Form 10-K or the Quarterly Report on Form 10-Q filed for the period ending June 30, 2009.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

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

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(10.1)	Retirement Agreement dated August 11, 2009 between Southwestern Energy Company and Harold M. Korell (Incorporated by reference to Exhibit 10.1 to the Registrant's Form 8-K filed on August 14, 2009)
(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.
(101.INS)	Interactive Data File Instance Document
(101.SCH)	Interactive Data File Schema Document
(101.CAL)	Interactive Data File Calculation Linkbase Document
(101.LAB)	Interactive Data File Label Linkbase Document
(101.PRE)	Interactive Data File Presentation Linkbase Document
(101.DEF)	Interactive Data File Definition Linkbase Document

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 29, 2009

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