SOUTHWESTERN ENERGY CO
Form 10-Q
July 31, 2009

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

Form 10-Q

(Mark One)

[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended **June 30, 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.
Yesx Noo

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) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yesx No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date:

Class	Outstanding as of July 27, 2009
Common Stock, Par Value $0.01	344,488,555
(including associated stock purchase rights)	

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2009

PART I FINANCIAL 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, targ

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:

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the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);

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our ability to transport our production to the most favorable markets or at all;

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

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

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our ability to fund our planned capital investments;

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

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the impact of federal, state and local government regulation, including any increase in severance taxes;

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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;

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our future property acquisition or divestiture activities;

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the effects of weather;

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increased competition;

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the financial impact of accounting regulations and critical accounting policies;

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the comparative cost of alternative fuels;

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conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;

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credit risk relating to the risk of loss as a result of non-performance by our counterparties; and

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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 June 30, 2009	For the three months ended June 30, 2008	For the six months ended June 30, 2009	For the six months ended June 30, 2008
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 367,430	$ 371,114	$ 740,088	$ 733,705
Gas marketing	91,438	205,836	243,010	341,143
Oil sales	1,693	15,538	2,875	29,251
Gas gathering	16,865	9,186	33,428	17,472
Other	94	2,696	(1,064)	6,905
	477,520	604,370	1,018,337	1,128,476
Operating Costs and Expenses:				
Gas purchases midstream services	91,187	202,889	240,367	335,341
Gas purchases gas distribution		9,544		61,439
Operating expenses	30,506	30,030	57,678	54,026
General and administrative expenses	29,200	25,741	52,909	49,481
Depreciation, depletion and amortization	117,927	98,151	242,155	195,248
Impairment of natural gas and oil properties			907,812	
Taxes, other than income taxes	6,473	8,729	15,681	16,145
	275,293	375,084	1,516,602	711,680
Operating Income (Loss)	202,227	229,286	(498,265)	416,796
Interest Expense:				
Interest on debt	13,725	15,659	27,910	32,745
Other interest charges	870	619	1,529	1,267
Interest capitalized	(11,529)	(7,281)	(22,689)	(13,486)

		3,066		8,997		6,750		20,526
Other Income		169		169		534		176
Income (Loss) Before Income Taxes		199,330		220,458		(504,481)		396,446
Provision (Benefit) for Income Taxes:								
Current				46,500		(35,500)		46,500
Deferred		78,272		37,193		(157,187)		104,017
		78,272		83,693		(192,687)		150,517
Net income (loss)		121,058		136,765		(311,794)		245,929
Less: net income (loss) attributable to noncontrolling interest		(42)		215		(64)		350
Net Income (Loss) Attributable to Southwestern Energy	$	121,100	$	136,550	$	(311,730)	$	245,579
Earnings Per Share:								
Net income (loss) attributable to Southwestern Energy stockholders Basic	$	0.35	$	0.40	$	(0.91)	$	0.72
Net income (loss) attributable to Southwestern Energy stockholders - Diluted	$	0.35	$	0.39	$	(0.91)	$	0.71
Weighted Average Common Shares Outstanding:								
Basic		342,960,373		341,402,888		342,766,760		341,233,574
Diluted		348,806,860		346,551,198		342,766,760		346,287,843

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)

	June 30, 2009	December 31, 2008
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 2,245	$ 196,277
Accounts receivable	213,404	254,557
Inventories	32,215	50,377
Hedging asset	349,318	343,320
Other	67,594	38,732
Total current assets	664,776	883,263
Property and Equipment:		
Gas and oil properties (using the full cost method), including costs excluded from amortization of $607.9 million in 2009 and $540.6 million in 2008	5,692,624	4,836,077
Gathering systems	435,976	341,474
Gas in underground storage	13,349	13,349
Other	156,551	138,014
Total property and equipment	6,298,500	5,328,914
Less: Accumulated depreciation, depletion and amortization	2,767,225	1,615,307
Property and equipment, net	3,531,275	3,713,607
Other Assets	142,231	163,288
TOTAL ASSETS	$ 4,338,282	$ 4,760,158
LIABILITIES AND EQUITY		
Current Liabilities:		
Short-term debt	$ 1,200	$ 61,200
Accounts payable	364,003	451,597
Taxes payable	23,459	31,951
Interest payable	20,116	20,857
Advances from partners	83,809	70,603
Hedging liability	5,952	10,899
Current deferred income taxes	130,222	122,448
Other	15,463	10,758
Total current liabilities	644,224	780,313

Long-Term Debt		869,600		674,200
Other Liabilities:				
Deferred income taxes		554,434		721,707
Long-term hedging liability		4,012		5,934
Pension and other postretirement liabilities		13,452		15,436
Other long-term liabilities		44,216		44,605
		616,114		787,682
Commitments and Contingencies				
Equity:				
Southwestern Energy stockholders equity				
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 344,486,505 shares in 2009 and 343,624,956 in 2008		3,445		3,436
Additional paid-in capital		822,428		811,492
Retained earnings		1,138,247		1,449,977
Accumulated other comprehensive income		238,550		247,665
Common stock in treasury, 203,059 shares in 2009 and 225,050 in 2008		(4,300)		(4,740)
Total Southwestern Energy stockholders equity		2,198,370		2,507,830
Noncontrolling interest		9,974		10,133
Total equity		2,208,344		2,517,963
TOTAL LIABILITIES AND EQUITY	$	4,338,282	$	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 six months ended June 30,	
	2009	2008
	(in thousands)	
Cash Flows From Operating Activities		
Net Income (loss)	$ (311,794)	$ 245,929
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	242,983	196,411
Impairment of natural gas and oil properties	907,812	
Deferred income taxes	(157,187)	104,017
Impairment of natural gas inventory	4,283	
Unrealized loss on derivatives	6,039	20,345
Stock-based compensation expense	5,810	5,839
Gain on sale of property and equipment		(392)
Distributions to noncontrolling interest in partnership	(95)	(202)
Change in assets and liabilities:		
Accounts receivable	41,152	(112,355)
Inventories	(424)	1,790
Accounts payable	(35,304)	85,948
Taxes payable	(8,492)	51,131
Interest payable	(741)	19,953
Advances from partners and customer deposits	13,207	11,003
Deferred tax benefit stock options		(39,332)
Other assets and liabilities	(33,518)	(1,833)
Net cash provided by operating activities	673,731	588,252
Cash Flows From Investing Activities		
Capital investments	(963,976)	(812,421)
Proceeds from sale of property and equipment		590,513
Other	(4,144)	(296)
Net cash used in investing activities	(968,120)	(222,204)
Cash Flows From Financing Activities		
Payments on short-term debt	(60,600)	(600)
Payments on revolving long-term debt	(339,500)	(1,843,600)
Borrowings under revolving long-term debt	535,500	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				39,332
Change in bank drafts outstanding		(38,401)		19,643
Proceeds from exercise of common stock options		3,358		2,067
Net cash provided by (used in) financing activities		100,357		(190,653)
Increase (decrease) in cash and cash equivalents		(194,032)		175,395
Cash and cash equivalents at beginning of year [1]		196,277		1,832
Cash and cash equivalents at end of period [1]	$	2,245	$	177,227

(1) Cash and cash equivalents at the beginning of the year for 2008 and at June 30, 2008 include $1.1 million and $0.1 million, respectively, 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		Additional		Accumulated Other	Common		
	Shares Issued	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income	Stock in Treasury	Noncontrolling Interest	Tota
					(in thousands)			
Balance at December 31, 2008	343,625	$ 3,436	$811,492	$1,449,977	$ 247,665	$ (4,740)	$ 10,133	$ 2,517,
Comprehensive income (loss):								

Net loss				(311,730)			(64)	(311,
Change in value of derivatives					(9,505)			(9,
Change in value of pension and other postretirement liabilities					390			
Total comprehensive loss							(64)	(320,
Stock-based compensation			7,383					7,
Exercise of stock options	851	9	3,349					3,
Issuance of restricted stock	16							
Cancellation of restricted stock	(5)							
Treasury stock non-qualified plan			204			440		
Distributions to noncontrolling interest in partnership							(95)	
Balance at June 30, 2009	344,487	$ 3,445	$822,428	$1,138,247	$ 238,550	$ (4,300)	$ 9,974	$ 2,208,

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 June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Net Income (Loss)	$ 121,058	$ 136,765	$ (311,794)	$ 245,929
Change in value of derivatives:				
Current period reclassification to earnings (1)	(103,543)	47,358	(188,096)	35,646
Current period ineffectiveness (2)	771	17,822	52	26,281
Current period change in derivative instruments (3)	8,577	(348,873)	178,539	(537,755)
Total change in value of derivatives	(94,195)	(283,693)	(9,505)	(475,828)
Current period change in value of pension and other postretirement liabilities (4)	194	210	390	419
Comprehensive income (loss)	27,057	(146,718)	(320,909)	(229,480)
Less: comprehensive income (loss) attributable to the noncontrolling interest	(42)	215	(64)	350
Comprehensive income (loss) attributable to Southwestern Energy	$ 27,099	$ (146,933)	$ (320,845)	$ (229,830)

(1) Current period reclassification to earnings is net of ($61.9), $29.0, ($115.5) and $21.8 million in taxes for the three and six months ended June 30, 2009 and 2008, respectively.

(2) Current period ineffectiveness is net of $0.5, $10.9, less than $0.1 and $16.1 million in taxes for the three and six months ended June 30, 2009 and 2008, respectively.

(3) Current period change in derivative instruments is net of $5.2, ($213.8), $113.0 and ($329.6) million in taxes for the three and six months ended June 30, 2009 and 2008, respectively.

(4) Current period change in the value of pension and other postretirement liabilities is net of $0.1, $0.1, $0.2 and $0.2 million in taxes for the three and six months ended June 30, 2009 and 2008, respectively.

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1)

BASIS OF PRESENTATION

Southwestern Energy Company (including its subsidiaries, collectively, the Company, Southwestern, we, us, its 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.

On January 1, 2009, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51 (SFAS 160). SFAS 160 establishes 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 adoption of SFAS 160 resulted in changes to our presentation for noncontrolling interests and did not have a material impact on the Company s results of operations and financial condition.

The Company adopted SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133 (SFAS 161), on January 1, 2009. SFAS 161 requires enhanced disclosure about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS 133) and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The adoption of SFAS 161 did not have a material impact on the Company s results of operations and financial condition.

On January 1, 2009, the Company adopted Financial Accounting Standards Board (FASB) Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2). FSP FAS 157-2 delayed the effective date of SFAS No. 157, Fair Value Measurements, 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 adoption of FSP FAS 157-2 did not have a material impact on the Company s results of operations and financial condition.

On June 30, 2009, the Company adopted FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP 107-1). FSP 107-1 requires that the fair value disclosures required for all financial instruments within the scope of SFAS No. 107, Disclosures about Fair Value of Financial Instruments, be included in interim financial statements. In addition, FSP 107-1 requires public companies to 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 adoption of FSP 107-1 did not have a material impact on the Company s results of operations and financial condition.

On June 30, 2009, the Company adopted SFAS No. 165, Subsequent Events (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Among other things, SFAS 165 requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. The adoption of SFAS 165 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. At June 30, 2009, the ceiling value of the Company s reserves was calculated based upon quoted market prices of $3.89 per MMBtu for Henry Hub natural gas and $66.25 per barrel for West Texas Intermediate oil, adjusted for market differentials. At June 30, 2009, the Company s net capitalized costs of its oil and gas properties did not exceed the ceiling value of the Company s reserves. Cash flow hedges of gas production in place at June 30, 2009 increased the calculated ceiling value by approximately $363.5 million (net of tax). Excluding the benefit of the cash flow hedges at June 30, 2009, unamortized costs would have exceeded the ceiling value by approximately $268.3 million (net of tax). Decreases in market prices subsequent to June 30, 2009 levels 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 six-month periods ended June 30, 2009 and 2008:

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
Net income (loss) attributable to Southwestern Energy (in thousands)	$ 121,100	$ 136,550	$ (311,730)	$ 245,579
Number of common shares:				
Weighted average outstanding	342,960,373	341,402,888	342,766,760	341,233,574
Issued upon assumed exercise of outstanding stock options	5,478,546	4,662,932		4,628,168
Effect of issuance of nonvested restricted common shares	367,941	485,378		426,101
Weighted average and potential dilutive outstanding[1]	348,806,860	346,551,198	342,766,760	346,287,843
Earnings per share:				
Net income (loss) attributable to Southwestern Energy stockholders - basic	$ 0.35	$ 0.40	$ (0.91)	$ 0.72
	$ 0.35	$ 0.39	$ (0.91)	$ 0.71

Net income (loss) attributable to Southwestern Energy stockholders - diluted

(1)

Options for 613,142 shares and 6,798 shares of restricted stock were excluded from the calculation for the three months ended June 30, 2009 because they would have had an antidilutive effect. Options for 5,577 shares and 22,601 shares of restricted stock were excluded from the calculation for the three months ended June 30, 2008 because they would have had an antidilutive effect. Due to the net loss for the six months ended June 30, 2009, options for 7,255,311 shares and 836,113 shares of restricted stock were antidilutive and excluded from the calculation. Options for 387,659 shares and 16,189 shares of restricted stock were excluded from the calculation for the six months ended June 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 operating results and cash flows from AWG are included in the unaudited condensed consolidated statements of operations and statements of cash flows for the three- and six-months ended June 30, 2008. The assets and liabilities of AWG were presented as "held for sale" in the June 30, 2008 condensed consolidated balance sheet. 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 six-month periods June 30, 2008.

(5)

DEBT

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

	June 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 (1.192% at June 30, 2009) unsecured revolving credit facility	196,000	
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	869,600	674,200
Total debt	$ 870,800	$ 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 June 30, 2009, the Company had $196.0 million in borrowings outstanding under the Credit Facility with a weighted average interest rate of 1.192%. 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 June 30, 2009, the Company is 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 June 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.

SFAS 133 requires that all derivatives be recognized in the balance sheet as either an asset or liability and be measured at fair value. Under SFAS 133, 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 the requirements of SFAS 133 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 is triggered when a net liability owed to the counterparty with the credit-risk-related contingent feature exceeds a threshold amount. The cash collateral amount that may be required to be remitted to the counterparty upon the trigger of the credit-risk-related contingent feature is equal to the net liability owed to the counterparty less the threshold amount. The derivative instrument containing the credit-risk-related contingent feature is in a net asset position as of June 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 June 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	$ 215,065	Hedging asset	$ 174,985

Costless-collars	Hedging asset		132,612	Hedging asset		165,671
Fixed and floating price swaps	Other Assets		48,558	Other Assets		66,349
Costless-collars	Other Assets		14,429	Other Assets		26,202
Total derivatives designated as hedging instruments		$	410,664		$	433,207
Derivatives not designated as hedging instruments						
Basis swaps	Hedging asset	$	1,641	Hedging asset	$	2,664
Basis swaps	Other Assets		441	Other Assets		1,844
Total derivatives not designated as hedging instruments		$	2,082		$	4,508
Total derivative assets		$	412,746		$	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	$	1,065	Hedging liability	$	2,679
Costless-collars	Hedging liability		992	Hedging liability		5,670
Fixed and floating price swaps	Long-term hedging liability		382	Long-term hedging liability		557
Costless-collars			1,099			5,142

	Long-term hedging liability			Long-term hedging liability		
Total derivatives designated as hedging instruments		$	3,538		$	14,048
Derivatives not designated as hedging instruments						
Basis swaps	Hedging liability	$	3,895	Hedging liability	$	2,550
Basis swaps	Long-term hedging liability		2,531	Long-term hedging liability		235
Total derivatives not designated as hedging instruments		$	6,426		$	2,785
Total derivative liabilities		$	9,964		$	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 June 30, 2009, the Company had cash flow hedges on the following volumes of gas production:

Natural Gas (Bcf):	
Fixed price swaps:	
2009	39.0
2010	36.0
Costless-collars:	
2009	27.0

2010	14.0

As of June 30, 2009, the Company recorded a net gain to other comprehensive income related to its hedging activities of $249.4 million. These amounts are net of a deferred income tax liability recorded as of June 30, 2009 of $156.1 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 June 30, 2009 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $211.9 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 $303.6 million for the six-month period ended June 30, 2009 compared to a realized loss of $57.5 million during the six-month period ended June 30, 2008. Volatility in earnings and other comprehensive income may occur in the future as a result of the application of SFAS 133.

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 six-month periods ended June 30, 2009 and 2008:

	Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion)			
	For the three months ended June 30,		For the six months ended June 30,	
Derivative Instrument	2009	2008	2009	2008
	(in thousands)			
Fixed price swaps	$ 12,369	$ (360,465)	$ 189,813	$ (573,325)
Costless-collars	$ 1,404	$ (154,779)	$ 101,692	$ (219,774)
Matched-basis swaps	$	$ 3,568	$	$ 4,190

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 June 30,		For the six months ended June 30,	
		2009	2008	2009	2008
		(in thousands)			
Fixed price swaps	Gas Sales	$ 115,925	$ (69,992)	$ 166,048	$ (62,946)
Costless-collars	Gas Sales	$ 49,530	$ (7,958)	$ 137,573	$ 4,828
Matched-basis swaps	Gas Sales	$	$ 1,437	$	$ 625

Derivative Instrument	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion)			
		For the three months ended June 30,		For the six months ended June 30,	
		2009	2008	2009	2008
		(in thousands)			
Fixed price swaps	Gas Sales	$ 670	$ (10,889)	$ 171	$ (16,500)
Costless-collars	Gas Sales	$ 561	$ (11,518)	$ (115)	$ (19,549)

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 June 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	0.2

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 June 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	$ 6	$ (6,633)	$ (644)	$ (872)

The following table summarizes the before tax effect of all fair value hedges on the unaudited condensed consolidated statements of operations for the six months ended June 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	$ (27)	$ (6,003)	$ 1,708	$ (142)

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 under SFAS 133. 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 six-month period ended June 30, 2009, gas sales included an unrealized loss of $6.1 million for non-qualifying basis swaps. For the six-month period ended June 30, 2008, gas sales included an unrealized gain of $21.7 million for non-qualifying basis swaps.

As of June 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	40.2
2010	39.3
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 June 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	$ (5,427)	$ 16,330	$ (1,497)	$ 7,825

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 six months ended June 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	$ (6,068)	$ 21,707	$ 1,366	$ 6,636

(7)

FAIR VALUE MEASUREMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate the value:

Cash and Cash Equivalents: The carrying amount is a reasonable estimate of 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 June 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 8.2% at June 30, 2009. Borrowings of $196.0 million under the Company s unsecured revolving credit facility at June 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 June 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	$ 2,245	$ 2,245	$ 196,277	$ 196,277
Total debt	$ 870,800	$ 841,072	$ 735,400	$ 648,616
Commodity hedges	$ 402,782	$ 402,782	$ 421,410	$ 421,410

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

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations -

Consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority.

Level 2 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 SFAS 157, 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:

June 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	$	$ 263,623	$ 149,123	$ 412,746
Derivative liabilities		(1,447)	(8,517)	(9,964)
Total	$	$ 262,176	$ 140,606	$ 402,782

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 six-month periods ended June 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 June 30, 2009.

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

	For the three months ended June 30, 2009	For the six months ended June 30, 2009
	(in thousands)	

Balance at beginning of period	$	193,036	$	182,823
Total gains or losses (realized/unrealized):				
Included in earnings		43,169		135,071
Included in other comprehensive income (loss)		(47,565)		(35,996)
Purchases, issuances and settlements		(48,034)		(141,292)
Transfers into/out of Level 3				
Balance at June 30, 2009	$	140,606	$	140,606
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of June 30, 2009	$	(4,865)	$	(6,221)

(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 June 30, 2009:					
Revenues from external customers	$ 369,098	$ 108,303	$	$ 119	$ 477,520
Intersegment revenues	3,583	228,861		112	232,556
Operating income	174,433	27,792		2	202,227
Interest and other income(1)	165			4	169
Depreciation, depletion and amortization expense	113,357	4,375		195	117,927
Interest expense(1)	2,609	457			3,066
Provision for income taxes(1)	67,908	10,361		3	78,272
Assets	3,662,225	565,224		110,833 (2)	4,338,282
Capital investments(3)	402,079	51,535		2,622	456,236
Three months ended June 30, 2008:					
Revenues from external customers	$ 355,493	$ 215,404	$ 33,473	$	$ 604,370
Intersegment revenues	22,232	424,354	46	112	446,744
Operating income (loss)	215,086	15,002	(857)	55	229,286
Interest and other income (loss)(1)	327		(163)	5	169
Depreciation, depletion and amortization expense	94,031	2,370	1,713	37	98,151
Interest expense(1)	4,807	3,081	1,109		8,997
Provision (benefit) for income taxes(1)	79,949	4,530	(809)	23	83,693
Assets	3,206,932	475,507	185,897	269,124 (2)	4,137,460
Capital investments(3)	362,821	47,878	2,583	2,260	415,542
Six months ended June 30, 2009:					
Revenues from external customers	$ 741,660	$ 276,438	$	$ 239	$ 1,018,337
Intersegment revenues	9,106	454,200		224	463,530
Operating income (loss)	(553,460) (4)	55,154		41	(498,265)
Interest and other income(1)	528			6	534
Depreciation, depletion and amortization expense	233,488	8,301		366	242,155
Impairment of natural gas and oil properties	907,812				907,812
Interest expense(1)	5,852	898			6,750

Provision (benefit) for income taxes(1)	(213,431)	20,726		18	(192,687)
Assets	3,662,225	565,224		110,833 (2)	4,338,282
Capital investments(3)	852,482	102,456		4,490	959,428
Six months ended June 30, 2008:					
Revenues from external customers	$ 654,512	$ 359,007	$ 114,957	$	$ 1,128,476
Intersegment revenues	35,230	686,076	2,753	224	724,283
Operating income	380,796	25,163	10,733	104	416,796
Interest and other income (loss)(1)	441		(270)	5	176
Depreciation, depletion and amortization expense	187,337	4,407	3,431	73	195,248
Interest expense(1)	13,577	4,632	2,317		20,526
Provision for income taxes(1)	139,578	7,802	3,095	42	150,517
Assets	3,206,932	475,507	185,897	269,124 (2)	4,137,460
Capital investments(3)	739,335	79,323	3,574	3,168	825,400

(1)

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

(2)

Other assets represent corporate assets not allocated to segments and assets, including investments in cash equivalents, for non-reportable segments.

(3)

Capital investments include reductions of $31.8 million and $8.2 million for the three- and six-month periods ended June 30, 2009, respectively, and a reduction of $6.8 million and an increase of $10.0 million for the three- and six-month periods ended June 30, 2008, respectively, relating to the change in accrued expenditures between periods.

(4)

The operating loss for the E&P segment for the six months ended June 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 $161.7 million and $389.0 million for the three months ended June 30, 2009 and 2008, respectively, and $357.0 million and $628.1 million for the six months ended June 30, 2009 and 2008, respectively, for marketing of the Company s E&P sales. Intersegment sales by the E&P segment and Midstream Services segment to the Natural Gas Distribution segment 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 of $5.3 million and $7.0 million were made for the three-month periods ended June 30, 2009 and 2008, respectively. Interest payments of $28.7 million and $12.7 million were made for the six-month periods ended June 30, 2009 and 2008, respectively. There were no tax payments made in these periods.

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

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Current	$	$ 46,500	$ (35,500)	$ 46,500
Deferred	78,272	37,193	(157,187)	104,017
Provision (benefit) for income taxes	$ 78,272	$ 83,693	$ (192,687)	$ 150,517

During 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 June 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 six-months ended June 30, 2009, the Company recorded compensation cost of $1.2 million and $2.3 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.5 million and $1.0 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool. The Company also recorded a deferred tax benefit of $0.4 million related to stock options for the six months ended June 30, 2009 compared to a deferred tax benefit of $0.2 million for the comparable period of 2008. As of June 30, 2009, a total of $9.9 million of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods. For the three- and six-months ended June 30, 2008, the Company recorded compensation cost of $0.7 million and $1.5 million, respectively, in general and administrative expense related to stock options. Additional amounts of $0.3 million and $0.5 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool.

For the three- and six-months ended June 30, 2009, the Company recorded compensation cost of $1.1 million and $2.2 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $0.9 million and $1.9 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool. As of June 30, 2009, there was $16.5 million of total unrecognized compensation cost related to nonvested shares of restricted stock. For the three- and six-months ended June 30 2008, the Company recorded compensation cost of $0.8 million and $1.7 million, respectively, in general and administrative expense related to restricted stock grants. Additional amounts of $0.6 million and $1.3 million for the same respective periods were directly related to the acquisition, exploration and development activities for the Company s gas and oil properties and were capitalized into the full cost pool.

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

	Number of Options	Weighted Average Exercise Price	
Outstanding at December 31, 2008	7,396,537	$	7.44
Granted	78,525		35.14
Exercised	(850,933)		3.95
Forfeited or expired	(7,000)		31.21
Outstanding at June 30, 2009	6,617,129	$	8.19
Exercisable at June 30, 2009	5,605,861	$	4.36

For the six months ended June 30, 2009 there were 78,525 options granted compared to 31,500 options granted during the first six months of 2008. The total intrinsic value of options exercised during the first six months of 2009 and 2008 was $31.6 million and $43.6 million, respectively.

Options Outstanding Options Exercisable

Range of Exercise Prices	Options Outstanding at June 30, 2009	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at June 30, 2009	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)
$0.75 - $1.00	1,592,615	$ 0.92	1.3		1,592,615	$ 0.92	1.3	
$1.01 - $2.50	1,711,682	1.38	3.0		1,711,682	1.38	3.0	
$2.51 - $16.75	1,627,234	4.10	3.8		1,627,234	4.10	3.8	
$16.76 - $30.00	1,061,978	22.16	4.5		666,081	20.39	4.1	
$30.01 - $45.19	623,620	32.34	6.4		8,249	41.56	6.1	
	6,617,129	$ 8.19	3.4	$ 202,884	5,605,861	$ 4.36	2.9	$ 193,367

The following table summarizes restricted stock activity for the six months ended June 30, 2009.

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2008	843,430	$ 27.66
Granted	16,230	33.38
Vested	(34,622)	28.88
Forfeited	(5,614)	28.97
Unvested shares at June 30, 2009	819,424	$ 27.71

(13) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS 158). Substantially all employees are covered by the Company s defined benefit pension and postretirement benefit plans. Net periodic pension and other postretirement benefit costs include the following components for the three- and six-month periods ended June 30, 2009 and 2008:

	Pension Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Service cost	$ 1,287	$ 1,408	$ 2,574	$ 2,816
Interest cost	718	1,208	1,436	2,418
Expected return on plan assets	(702)	(1,254)	(1,404)	(2,509)
Amortization of prior service cost	84	122	167	244
Amortization of net loss	211	175	423	349
Net periodic benefit cost	$ 1,598	$ 1,659	$ 3,196	$ 3,318

	Postretirement Benefits			
	For the three months ended June 30,		For the six month ended June 30,	
	2009	2008	2009	2008
	(in thousands)			
Service cost	$ 174	$ 165	$ 348	$ 330
Interest cost	34	78	68	155
Expected return on plan assets		(24)		(48)
Amortization of transition obligation	16	22	32	44
Amortization of prior service cost	4	3	7	6
Amortization of net loss	2	17	4	34

Net periodic benefit cost	$	230	$	261	$	459	$	521

The Company currently expects to contribute $9.0 million to the pension plans and $0.1 million to the postretirement benefit plans in 2009. As of June 30, 2009, $5.0 million has been contributed to the pension plans and there have been no contributions 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 June 30, 2009, treasury stock held by the Company under the terms of the Non-Qualified Plan totaled 203,059 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 June 30, 2009 is $9.6 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 June 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 six months ended June 30, 2009.

Also included in current inventory at June 30, 2009 and December 31, 2008, are $22.6 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 $44.8 million at June 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 FSP FAS 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets (FSP FAS 132(R)-1). This FSP amends SFAS No. 132(R), Employers Disclosures about Pensions and Other Postretirement Benefits to require more detailed disclosures about the fair value measurements of employers plan assets including: (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 required by FSP FAS 132(R)-1 will be included in the Company s year ending 2009 consolidated financial statements and is not expected to have a material impact on the Company s consolidated financial statements.

In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162 (SFAS 168). SFAS 168 establishes the FASB Accounting Standards Codification as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. SFAS 168 is effective for the period ending September 30, 2009. SFAS 168 does not change GAAP and will not 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 (in thousands)	Eliminations	Consolidated
Three months ended June 30, 2009:					
Operating revenues	$	$ 460,436	$ 49,263	$ (32,179)	$ 477,520
Operating costs and expenses:					
Gas purchases		91,686		(499)	91,187
Operating expenses		46,836	15,238	(31,568)	30,506
General and administrative expenses		26,129	3,183	(112)	29,200
Depreciation, depletion and amortization		112,558	5,369		117,927
		5,691	782		6,473

Taxes, other than income taxes					
Total operating costs and expenses		282,900	24,572	(32,179)	275,293
Operating income		177,536	24,691		202,227
Other income		165	4		169
Equity in earnings of subsidiaries	121,100			(121,100)	
Interest expense		2,405	661		3,066
Income (loss) before income taxes	121,100	175,296	24,034	(121,100)	199,330
Provision for income taxes		69,152	9,120		78,272
Net income (loss)	121,100	106,144	14,914	(121,100)	121,058
Less: Net (loss) attributable to noncontrolling interest		(42)			(42)
Net income (loss) attributable to Southwestern Energy	$ 121,100	$ 106,186	$ 14,914	$ (121,100)	$ 121,100

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
<u>Three months ended June 30, 2008:</u>					
Operating revenues	$	$ 577,034	$ 64,105	$ (36,769)	$ 604,370
Operating costs and expenses:					
Gas purchases		212,903	20,464	(20,934)	212,433
Operating expenses		28,394	17,324	(15,688)	30,030
General and administrative expenses		19,416	6,472	(147)	25,741
Depreciation, depletion and amortization		93,762	4,389		98,151
Taxes, other than income taxes		7,206	1,523		8,729
Total operating costs and expenses		361,681	50,172	(36,769)	375,084
Operating income		215,353	13,933		229,286
Other income (loss)		328	(159)		169
	136,550			(136,550)	

Equity in earnings of subsidiaries										
Interest expense				4,273		4,724				8,997
Income (loss) before income taxes		136,550		211,408		9,050		(136,550)		220,458
Provision for income taxes				80,254		3,439				83,693
Net income (loss)		136,550		131,154		5,611		(136,550)		136,765
Less: Net income attributable to noncontrolling interest				215						215
Net income (loss) attributable to Southwestern Energy	$	136,550	$	130,939	$	5,611	$	(136,550)	$	136,550

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent		Guarantors		Non-Guarantors (in thousands)		Eliminations		Consolidated	
<u>Six months ended June 30, 2009:</u>										
Operating revenues	$		$	985,265	$	92,316	$	(59,244)	$	1,018,337
Operating costs and expenses:										
Gas purchases				240,932				(565)		240,367
Operating expenses				87,716		28,417		(58,455)		57,678
General and administrative expenses				46,949		6,184		(224)		52,909
Depreciation, depletion and amortization				232,344		9,811				242,155
				907,812						907,812

Impairment of natural gas and oil properties					
Taxes, other than income taxes		14,141	1,540		15,681
Total operating costs and expenses		1,529,894	45,952	(59,244)	1,516,602
Operating income (loss)		(544,629)	46,364		(498,265)
Other income		526	8		534
Equity in earnings of subsidiaries	(311,730)			311,730	
Interest expense		5,354	1,396		6,750
Income (loss) before income taxes	(311,730)	(549,457)	44,976	311,730	(504,481)
Provision (benefit) for income taxes		(209,868)	17,181		(192,687)
Net income (loss)	(311,730)	(339,589)	27,795	311,730	(311,794)
Less: Net (loss) attributable to noncontrolling interest		(64)			(64)
Net income (loss) attributable to Southwestern Energy	$ (311,730)	$ (339,525)	$ 27,795	$ 311,730	$ (311,730)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Six months ended June 30, 2008:					
Operating revenues	$	$ 1,027,645	$ 170,825	$ (69,994)	$ 1,128,476
Operating costs and expenses:					
Gas purchases		359,776	79,120	(42,116)	396,780
Operating expenses		50,296	31,319	(27,589)	54,026
General and administrative expenses		37,115	12,655	(289)	49,481
Depreciation, depletion and amortization		186,769	8,479		195,248
Taxes, other than income taxes		13,140	3,005		16,145
		647,096	134,578	(69,994)	711,680

Total operating costs and expenses					
Operating income		380,549	36,247		416,796
Other income (loss)		441	(265)		176
Equity in earnings of subsidiaries	245,579			(245,579)	
Interest expense		12,865	7,661		20,526
Income (loss) before income taxes	245,579	368,125	28,321	(245,579)	396,446
Provision for income taxes		139,755	10,762		150,517
Net income (loss)	245,579	228,370	17,559	(245,579)	245,929
Less: Net income attributable to noncontrolling interest		350			350
Net income (loss) attributable to Southwestern Energy	$ 245,579	$ 228,020	$ 17,559	$ (245,579)	$ 245,579

CONDENSED CONSOLIDATING BALANCE SHEETS

(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
June 30, 2009:					
ASSETS					
Cash and cash equivalents	$ 2,206	$	$ 39	$	$ 2,245
Accounts receivable	383	202,774	10,247		213,404
Inventories		31,339	876		32,215

Other	24,355	392,247	310		416,912
Total current assets	26,944	626,360	11,472		664,776
Intercompany receivables	1,560,052	(1,138,712)	(410,723)	(10,617)	
Investments		10,482	(10,481)	(1)	
Property and equipment	60,831	5,702,385	535,284		6,298,500
Accumulated depreciation, depletion and amortization	(34,323)	(2,685,534)	(47,368)		(2,767,225)
Net property and equipment	26,508	3,016,851	487,916		3,531,275
Investments in subsidiaries (equity method)	1,500,650			(1,500,650)	
Other assets	18,218	71,147	52,866		142,231
Total assets	$ 3,132,372	$ 2,586,128	$ 131,050	$ (1,511,268)	$ 4,338,282
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 124,478	$ 275,293	$ 19,625	$ (10,618)	$ 408,778
Other current liabilities	1,910	227,494	6,042		235,446
Total current liabilities	126,388	502,787	25,667	(10,618)	644,224
Long-term debt	869,600				869,600
Other liabilities	31,631	25,250	4,799		61,680
Commitments and contingencies					
Deferred income taxes	(103,591)	626,552	31,473		554,434
Total liabilities	924,028	1,154,589	61,939	(10,618)	2,129,938
Total equity	2,208,344	1,431,539	69,111	(1,500,650)	2,208,344
Total liabilities and equity	$ 3,132,372	$ 2,586,128	$ 131,050	$ (1,511,268)	$ 4,338,282

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
Six months ended June 30, 2009:					
Net cash provided by operating activities	$ 5,169	$ 629,310	$ 39,252	$	$ 673,731
Investing activities:					
Capital investments	(4,851)	(847,171)	(111,954)		(963,976)
Other	3,644	(17,563)	9,775		(4,144)
Net cash used in investing activities	(1,207)	(864,734)	(102,179)		(968,120)
Financing activities:					
Intercompany activities	(298,082)	235,424	62,658		
Payments on short-term debt	(60,600)				(60,600)
Payments on revolving long-term debt	(339,500)				(339,500)
	535,500				535,500

Borrowings under revolving long-term debt					
Change in bank drafts outstanding	(38,401)				(38,401)
Proceeds from exercise of common stock options	3,358				3,358
Net cash provided by (used in) financing activities	(197,725)	235,424	62,658		100,357
Increase (decrease) in cash and cash equivalents	(193,763)		(269)		(194,032)
Cash and cash equivalents at beginning of year	195,969		308		196,277
Cash and cash equivalents at end of period	$ 2,206	$	$ 39	$	$ 2,245
<u>Six months ended June 30, 2008:</u>					
Net cash provided by (used in) operating activities	$ (4)	$ 549,753	$ 38,503	$	$ 588,252
Investing activities:					
Capital investments	(3,286)	(729,252)	(79,883)		(812,421)
Proceeds from sale of property, plant and equipment		542,092	48,421		590,513
Other	3,047	3,999	(7,342)		(296)
Net cash used in investing activities	(239)	(183,161)	(38,804)		(222,204)
Financing activities:					
Intercompany activities	367,024	(366,592)	(432)		
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
Excess tax benefit for stock-based compensation	39,332				39,332
Change in bank drafts outstanding	19,643				19,643
Proceeds from exercise of common stock options	2,067				2,067
Debt issuance costs and revolving credit facility costs	(8,895)				(8,895)
Net cash provided by (used in) financing activities	176,371	(366,592)	(432)		(190,653)
Increase (decrease) in cash and cash equivalents	176,128		(733)		175,395
Cash and cash equivalents at beginning of year	433		1,399 (1)		1,832
Cash and cash equivalents at end of period	$ 176,561	$	$ 666 (1)	$	$ 177,227

(1)

Cash and cash equivalents at the beginning of the year for 2008 and at June 30, 2008 include $1.1 million and $0.1 million, respectively, classified as held for sale. See Note 4 for additional information.

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SUBSEQUENT EVENTS

The Company evaluates subsequent events through the date the financial statements are issued, which for the quarterly period ended June 30, 2009, is July 30, 2009. No 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 six-month periods ended June 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 for the three- and six-months ended June 30, 2008 are included in the unaudited condensed consolidated statements of operations and statements of cash flows 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 continued development of our Fayetteville Shale play, we have experienced significant growth in our production volumes in the first half of 2009 as compared with the prior year. This growth in our production has been partially offset by the decrease in our revenues due to 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 upon the Fayetteville and Greenville Laterals built by Texas Gas Transmission, LLC ("Texas Gas"), a subsidiary of Boardwalk Pipeline Partners, LP, which went into service on April 1, 2009, to service our increased production from the Fayetteville Shale play. As a result of recent inspections, repairs and maintenance on the Fayetteville Lateral, we have experienced curtailments that have impacted our ability to transport our production from the Fayetteville Shale. Beginning in April 2009, Texas Gas reduced the capacity on, or shut down, the Fayetteville Lateral on several occasions due to various activities, including maintenance and pipeline inspection. These activities, as well as similar repairs to the Greenville Lateral, are expected to continue, resulting in future curtailments. Texas Gas has estimated that it will begin repairs and maintenance on the pipeline beginning in September and that the repairs will be completed in one to five months.

In anticipation of these continued pipeline curtailments, we have revised our previous gas and oil production guidance range for 2009 from 289 to 292 Bcfe to 278 to 288 Bcfe, an increase of approximately 45% over 2008 levels (using midpoints). This revised production guidance assumes curtailment of portions of the Fayetteville Lateral Phase 1 facilities for 45 to 60 days starting in September 2009 and total curtailed volumes for the remainder of the year of approximately 15 Bcf net to Southwestern.

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

Our natural gas and oil production increased to 74.3 Bcfe for the three months ended June 30, 2009, up 65% from the three months ended June 30, 2008. The 29.2 Bcfe increase in 2009 production was due to a 31.0 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program, 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 39% to $5.01 per Mcf for the three months ended June 30, 2009, as compared to the same period in 2008.

We reported net income attributable to Southwestern Energy of $121.1 million for the three months ended June 30, 2009, or $0.35 per diluted share, compared to net income attributable to Southwestern Energy of $136.6 million, or $0.39 per diluted share, for the comparable period in 2008.

Our E&P segment reported operating income of $174.4 million for the three months ended June 30, 2009, down $40.7 million from the comparable period of 2008, primarily due to the effect of decreased gas prices realized from the sale of our production and an increase in operating costs and expenses of $35.6 million relating to our increased production volumes. Operating income for our Midstream Services segment was $27.8 million for the three months ended June 30, 2009, up from $15.0 million for the three months ended June 30, 2008, due to an increase of $21.8 million in gathering revenues, which were partially offset by an $8.8 million increase in operating costs and expenses, exclusive of gas purchase costs, and a decrease of $0.3 million in the margin generated from our natural gas marketing activities. Our Natural Gas Distribution segment had a seasonal operating loss of $0.9 million for the three months ended June 30, 2008.

We had capital investments of $456.2 million for the three months ended June 30, 2009, of which $402.1 million was invested in our E&P segment compared to $415.5 million for the same period of 2008, of which $362.8 million was invested in our E&P segment.

Six Months Ended June 30, 2009 Compared with Six Months Ended June 30, 2008

For the six months ended June 30, 2009, our gas and oil production increased to 138.2 Bcfe, up 64% compared to the same period in 2008. The 54.1 Bcfe increase in 2009 production was due to a 57.6 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program, 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 32% to $5.44 per Mcf for the six months ended June 30, 2009, as compared to the same period last year.

We reported a net loss attributable to Southwestern Energy of $311.7 million for the six months ended June 30, 2009, or $0.91 per diluted share, down from net income attributable to Southwestern Energy of $245.6 million, or $0.71 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 a significant decline in natural gas prices.

Our E&P segment reported an operating loss of $553.5 million for the six months ended June 30, 2009, down $934.3 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, an increase in operating costs and expenses of $87.5 million relating to our increased gas production which offset the higher revenues of $417.8 million realized from increased gas production volumes. Operating income for our Midstream Services segment was $55.2 million for the six months ended June 30, 2009, up from $25.2 million for the six months ended June 30, 2008, due to a $44.7 million increase in gathering revenues and a $3.7 million increase in the margin generated from our natural gas marketing activities, which were partially offset by a $18.4 million increase in operating costs and expenses,

exclusive of gas purchase costs. Our Natural Gas Distribution segment had operating income of $10.7 million for the six months ended June 30, 2008.

We had capital investments of $959.4 million for the six months ended June 30, 2009, of which $852.5 million was invested in our E&P segment compared to $825.4 million for the same period of 2008, of which $739.3 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 June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
Revenues (in thousands)	$ 372,681	$ 377,725	$ 750,766	$ 689,742

Impairment of natural gas and oil properties (in thousands)	$		$		$	907,812	$	
Operating costs and expenses (in thousands)	$	198,248	$	162,639	$	396,414	$	308,946
Operating income (loss) (in thousands)	$	174,433	$	215,086	$	(553,460)	$	380,796
Gas production (MMcf)		74,120		44,312		137,809		82,517
Oil production (MBbls)		32		127		66		269
Total production (MMcfe)		74,315		45,075		138,208		84,132
Average gas price per Mcf, including hedges	$	5.01	$	8.17	$	5.44	$	7.95
Average gas price per Mcf, excluding hedges	$	2.90	$	10.00	$	3.32	$	8.82
Average oil price per Bbl	$	51.91	$	122.26	$	43.24	$	108.69
Average unit costs per Mcfe:								
Lease operating expenses	$	0.73	$	0.95	$	0.76	$	0.87
General & administrative expenses	$	0.34	$	0.41	$	0.32	$	0.42
Taxes, other than income taxes	$	0.08	$	0.16	$	0.10	$	0.16
Full cost pool amortization	$	1.46	$	2.01	$	1.63	$	2.15

Revenues

Revenues for our E&P segment were down $5.0 million, or 1%, for the three months ended June 30, 2009 compared to the same period in 2008. Lower natural gas and oil prices in the second quarter of 2009 decreased revenues by $236.8 million, which were substantially offset by $232.0 million of revenue attributable to increased production volumes. E&P revenues were up $61.0 million, or 9%, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. The $61.0 million increase was attributable to increased revenues of $417.8 million from increased production volumes which were partially offset by a $351.3 million decrease attributable to lower realized natural gas and oil prices, a $4.3 million decrease related to the non-cash impairment of our natural gas inventory and a $1.2 million decrease resulting from other changes in our revenue. 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 July 27, 2009, we had hedged 66.0 Bcf of our remaining 2009 gas production and 50.0 Bcf of 2010 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 June 30, 2009 was up approximately 65%, from the comparable period in 2008, to 74.3 Bcfe, due to a 31.0 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 1.2 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 three months ended June 30, 2009 and was up approximately 67% to 74.1 Bcf compared to the same period in 2008. Net production from the Fayetteville Shale was 60.6 Bcf for the three months ended June 30, 2009 compared to 29.6 Bcf for the same period in 2008.

Natural gas and oil production for the six months ended June 30, 2009 was up approximately 64%, from the comparable period in 2008, to 138.2 Bcfe, due to a 57.6 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 2.5 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 six months ended June 30, 2009 and was up approximately 67% to 137.8 Bcf compared to the same period in 2008. Net production from the Fayetteville Shale was 110.8 Bcf for the six months ended June 30, 2009 compared to 53.2 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 upon the Fayetteville and Greenville Laterals built by Texas Gas, which went into service on April 1, 2009, to service our increased production from the Fayetteville Shale play. As a result of recent inspections, repairs and maintenance on the Fayetteville Lateral, we have experienced curtailments that have impacted our ability to transport our production from the Fayetteville Shale. Beginning in April 2009, Texas Gas reduced the capacity on, or shut down, the Fayetteville Lateral on several occasions due to various activities, including maintenance and pipeline inspection. These activities, as well as similar repairs to the Greenville Lateral, are expected to continue, resulting in future curtailments. Texas Gas has estimated that it will begin repairs and maintenance on the pipeline beginning in September and that the repairs will be completed in one to five months.

In anticipation of these continued pipeline curtailments, we have revised our previous gas and oil production guidance range for 2009 from 289 to 292 Bcfe to 278 to 288 Bcfe, an increase of approximately 45% over 2008 levels (using midpoints). This revised production guidance assumes curtailment of portions of the Fayetteville Lateral Phase 1 facilities for 45 to 60 days starting in September 2009 and total curtailed volumes for the remainder of the year of approximately 15 Bcf net to Southwestern.

Commodity Prices

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 3 and Note 6 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion). The average price realized for our gas production, including the effects of hedges, decreased approximately 39% to $5.01 per Mcf for the three months ended June 30, 2009, and decreased 32% to $5.44 per Mcf for the six months ended June 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.

Our hedging activities increased the average gas price $2.11 per Mcf for the three months ended June 30, 2009 compared to a decrease of $1.83 per Mcf for the same period in 2008. Our hedging activities increased the average gas price $2.12 per Mcf for the six months ended June 30, 2009 compared to a decrease of $0.87 per Mcf for the same period in 2008. We had protected approximately 62% of our gas production for the six months ended June 30, 2009 from the impact of widening basis differentials through our hedging activities and sales arrangements. Additionally, as of July 27, 2009, we have basis protected on approximately 80 Bcf of our remaining 2009 expected gas production through hedging activities and sales arrangements at a basis differential to NYMEX gas prices of approximately $0.35 per Mcf, excluding transportation charges and fuel charges. Disregarding the impact of hedges, the average price received for our gas production for the six months ended June 30, 2009 was approximately $0.87 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 July 27, 2009, we had NYMEX fixed price hedges in place on notional volumes of 39.0 Bcf of our remaining 2009 gas production at an average price of $8.30 per MMBtu and collars in place on notional volumes of 27.0 Bcf of our remaining 2009 gas production at an average floor and ceiling price of $8.61 and $11.36 per MMBtu, respectively.

As of July 27, 2009, we had NYMEX fixed price hedges in place on notional volumes of 36.0 Bcf of our 2010 gas production and collars in place on notional volumes of 14.0 Bcf of our 2010 gas production. Additionally, we have basis swaps on 48.7 Bcf for the remainder of 2009, 44.7 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 19% to $174.4 million for the three months ended June 30, 2009 compared to $215.1 million for the same period in 2008. The $40.7 million decrease in operating income was the result of a 1% 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 22% increase in operating costs and expenses. We recorded an operating loss from our E&P segment of $553.5 million for the six months ended June 30, 2009, which represents a decline of $934.3 million from the same period in 2008. The $934.3 million decrease in operating income was the result of a $907.8 million non-cash ceiling test impairment resulting from lower natural gas prices and an increase in other operating costs and expenses of $87.5 million, or 28%, which were partially offset by a $61.0 million, or 9%, increase in revenues.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.73 for the three months ended June 30, 2009 compared to $0.95 for the same period in 2008. Lease operating expenses per Mcfe for our E&P segment were $0.76 for the six months ended June 30, 2009 compared to $0.87 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 decreased 17% to $0.34 for the three months ended June 30, 2009 and decreased 24% to $0.32 for the six months ended June 30, 2009 compared to the same periods in 2008, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $25.0 million for the three months ended June 30, 2009 compared to $18.4 million for the same period in 2008, and were $44.7 million for the six months ended June 30, 2009 compared to $34.9 million for the same period in 2008. The increases in general and administrative expenses were due to increases in payroll, incentive compensation and employee-related costs associated with the expansion of our E&P operations due to the Fayetteville Shale play. These increases accounted for $4.1 million, or 62%, of the increase for the three months ended June 30, 2009 compared to the same period in 2008, and accounted for $6.9 million, or 70%, of the increase for the six months ended June 30, 2009 compared to the same period in 2008.

Taxes other than income taxes per Mcfe decreased to $0.08 for the three months ended June 30, 2009 compared to $0.16 for the same period in 2008 and decreased to $0.10 for the six months ended June 30, 2009 compared to $0.16 for the same period 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 $2.3 million or $0.03 per Mcfe for the three months ended June 30, 2009 compared to the same period in 2008, and by $5.8 million or

$0.04 per Mcfe for the six months ended June 30, 2009 compared to the same period in 2008.

Our full cost pool amortization rate averaged $1.46 per Mcfe for the three months ended June 30, 2009 compared to $2.01 per Mcfe for the same period in 2008. For the first six months of 2009, our full cost pool amortization rate averaged $1.63 per Mcfe compared to $2.15 per Mcfe for the same period in 2008. The decline in the average amortization rate for the three months ended June 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 while the decline in the average amortization rate for the six months ended June 30, 2009 compared to the same period of 2008 was the result of the $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009 and sales of natural gas and oil properties in the second and third quarters of 2008, as the proceeds from these sales were credited to the full cost pool. The amortization rate is impacted by 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 $607.9 million at June 30, 2009 compared to $540.6 million at December 31, 2008. The increase in unevaluated costs since December 31, 2008, resulted primarily from a $35.8 million increase in our undeveloped leasehold acreage and seismic costs (with $20.0 million of the increase related to our Fayetteville Shale play) and a $12.7 million increase in our drilling activity.

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

Midstream Services

	For the three months ended June 30,		For the six months ended June 30,	
	2009	2008	2009	2008
	($ in thousands, except volumes)			
Revenues marketing	$ 288,450	$ 612,884	$ 639,506	$ 998,605
Revenues gathering	$ 48,714	$ 26,874	$ 91,132	$ 46,478

Gas purchases marketing	$ 285,208	$ 609,366	$ 629,611	$ 992,426
Operating costs and expenses	$ 24,164	$ 15,390	$ 45,873	$ 27,494
Operating income	$ 27,792	$ 15,002	$ 55,154	$ 25,163
Gas volumes marketed (Bcf)	89.1	59.5	175.6	109.6
Gas volumes gathered (Bcf)	94.9	49.9	174.4	88.4

Revenues

Revenues from our Midstream Services segment were down 47% to $337.2 million for the three months ended June 30, 2009 compared to the same period in 2008, and were down 30% to $730.6 million for the six months ended June 30, 2009 compared to the same period in 2008. The decreases in marketing revenues for the three- and six-month periods ended June 30, 2009 compared to the same periods in 2008 resulted from a decrease in the price received for volumes marketed and were partially offset by increases in gas volumes marketed. For the three months ended June 30, 2009, the price received for volumes marketed decreased 69% compared to the same period in 2008 and decreased 60% for the six months ended June 30, 2009 compared to the same period in 2008. For the three months ended June 30, 2009, the volumes marketed increased 50% compared to the same period in 2008 and increased 60% for the six months ended June 30, 2009 compared to the same period in 2008.

Of the total volumes marketed, production from our E&P operated wells accounted for 91% and 96% of the marketed volumes for the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009, production from our E&P operated wells accounted for 93% 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 June 30, 2009 and for the six months ended June 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 $12.8 million to $27.8 million for the three months ended June 30, 2009 compared to $15.0 million for the same period in 2008, and increased $30.0 million to $55.2 million for the six months ended June 30, 2009 compared to $25.2 million for the same period in 2008. The increases in operating income reflect the substantial increase in gas volumes marketed and gathered. The $12.8 million increase in operating income for three months ended June 30, 2009 was primarily due to a $21.8 million increase in gathering revenues and was partially offset by an increase in operating costs and expenses of $8.8 million. The $30.0 million increase in operating income for six months ended June 30, 2009 was primarily due to a $44.7 million increase in gathering revenues and was partially offset by an increase in operating costs and expenses of $18.4 million. The remaining changes in operating income were due to a decrease of $0.3 million in the margin generated by our gas marketing activities for the three months ended June 30, 2009 and an increase in the margin of $3.7 million for the six months ended June 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 six-month periods ended June 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 a seasonal operating loss of $0.9 million and operating income of $10.7 million for the three- and six-month periods ended June 30, 2008, respectively.

Interest Expense and Interest Income

Interest costs, net of capitalization, decreased to $3.1 million and $6.8 million for the three- and six-month periods ended June 30, 2009, respectively, compared to $9.0 million and $20.5 million for the same periods in 2008. The decreases were primarily due to increased capitalized interest. We capitalized interest of $11.5 million and $22.7 million for the three- and six-month periods ended June 30, 2009, respectively, compared to $7.3 million and $13.5 million for the same periods in 2008. Interest income for the three month period ended June 30, 2009 was less than $0.1 million compared to $0.2 million for the same period in 2008. Interest income for the six-month period ended June 30, 2009 was $0.4 million compared to $0.2 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 rates were 38.2% and 38.0% for the six months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009, we recorded an income tax benefit of $192.7 million compared to an income tax expense of $150.5 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 June 30, 2009 for our pension and other postretirement benefit plans compared to $1.9 million for the same period in 2008. For the six months ended June 30, 2009, our pension costs were $3.7 million compared to $3.8 million for the same period in 2008. Contributing to the decreased pension expense was the AWG disposition which resulted in the transfer of pension and other postretirement plan assets and liabilities, related to the employees of AWG, to the purchaser of AWG. These decreases were partially offset by higher pension costs resulting from increases in average employee headcount, excluding our former employees of AWG, for the three- and six-month periods ended June 30, 2009 compared to the same periods in 2008.

The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $9.0 million to our pension plans and $0.1 million to our other postretirement benefit plans in 2009. As of June 30, 2009, $5.0 million has been contributed to the pension plans and there have been no contributions 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 $2.3 million and capitalized $1.4 million to the full cost pool for stock-based compensation for the three months ended June 30, 2009 compared to $1.5 million expensed and $0.9 million capitalized to the full cost pool for the comparable period in 2008. We recognized expense of $4.5 million and capitalized $2.9 million to the full cost pool for stock-based compensation for the six months ended June 30, 2009 compared to $3.2 million expensed and $1.8 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

On January 1, 2009, we adopted Statement of Financial Accounting Standards (SFAS) No. 160, Noncontrolling Interests in Consolidated Financial Statements - An Amendment of ARB No. 51 (SFAS 160). SFAS 160 establishes 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 adoption of SFAS 160 resulted in changes to our presentation for noncontrolling interests and did not have a material impact on our results of operations and financial condition.

We adopted SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133 (SFAS 161), on January 1, 2009. SFAS 161 requires enhanced disclosure about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS 133) and (3) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The adoption of SFAS 161 did not have a material impact on our results of operations and financial condition.

On January 1, 2009, we adopted Financial Accounting Standards Board (FASB) Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2). FSP FAS 157-2 delayed the effective date of SFAS No. 157, Fair Value Measurements, 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 adoption of FSP FAS 157-2 did not have a material impact on our results of operations and financial condition.

On June 30, 2009, we adopted FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (FSP 107-1). FSP 107-1 requires that the fair value disclosures required for all financial instruments within the scope of SFAS No. 107, Disclosures about Fair Value of Financial Instruments, be included in interim financial statements. In addition, FSP 107-1 requires public companies to 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 adoption of FSP 107-1 did not have a material impact on our results of operations and financial condition.

On June 30, 2009, we adopted SFAS No. 165, Subsequent Events (SFAS 165). SFAS 165 establishes general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Among other things, SFAS 165 requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. The adoption of SFAS 165 did not have a material impact on our results of operations and financial condition.

In December 2008, the FASB issued FSP FAS 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets (FSP FAS 132(R)-1). This FSP amends SFAS No. 132(R), Employers Disclosures about Pensions and Other Postretirement Benefits to require more detailed disclosures about the fair value measurements of employers plan assets including: (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 required by FSP FAS 132(R)-1 will be included in our year ending 2009 consolidated financial statements and is not expected to have a material impact on our consolidated financial statements.

In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162 (SFAS 168). SFAS 168 establishes the FASB Accounting Standards Codification as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with

GAAP. SFAS 168 is effective for the period ending September 30, 2009 consolidated financial statements. SFAS 168 does not change GAAP and will not 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 June 30, 2009, we had borrowings of $196.0 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 15% to $673.7 million for the six months ended June 30, 2009 compared to $588.3 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 six months ended June 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 June 30, 2009, our capital structure consisted of 28% debt and 72% 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 $959.4 million for the six months ended June 30, 2009 compared to $825.4 million for the same period in 2008. Our E&P segment investments were $852.5 million for the six months ended June 30, 2009 and were $739.3 million for the same period in 2008. Our E&P segment capitalized internal costs of $49.8 million for the six months ended June 30, 2009 compared to $38.2 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 Southwestern s 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 June 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 $870.8 million at June 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 June 30, 2009, we had borrowings of $196.0 million under our Credit Facility 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 agreement, 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. We were in compliance with all of the covenants of the Credit Facility at June 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 June 30, 2009, our capital structure consisted of 28% debt and 72% equity. Our debt as a percentage of total capital increased during the six months ended June 30, 2009 primarily due to our net loss of $311.7 million for the six months ended June 30, 2009 that resulted from our first quarter ceiling test impairment. Equity at June 30, 2009 also includes an accumulated other comprehensive gain of $249.4 million related to our hedging activities that is required to be recorded under the provisions of SFAS 133 and a loss of $10.8 million related to our pension and other postretirement liabilities. The amount recorded for SFAS 133 is based on current market values of our hedges at June 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. Our Credit Facility s financial covenants with respect to capitalization percentages exclude the effects of non-cash entries that result from any full cost ceiling write-downs, SFAS 133 or SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. Our capital structure at June 30, 2009 would have been 26% debt and 74% equity without consideration of the ceiling test impairment, the noncontrolling interest in equity and accumulated other comprehensive income in equity related to our commodity hedge position and our pension and other postretirement liabilities.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged 66.0 Bcf of our remaining 2009 gas production and 50.0 Bcf of our expected 2010 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 $0.1 million to our postretirement benefit plans in 2009. As of June 30, 2009, we have contributed $5.0 million to our pension plans and have made no contributions to our postretirement benefit plans. At June 30, 2009, we recognized a liability of $13.5 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 positive working capital of $20.6 million at June 30, 2009, and positive working capital of $103.0 million at December 31, 2008. Current assets decreased $218.5 million at June 30, 2009 compared to current assets at December 31, 2008, due to a $195.0 million decrease in cash equivalents, a $41.2 million decrease in accounts receivable and an $18.2 million decrease in inventory, which included a $4.3 million non-cash impairment charge in the first quarter of 2009 to reduce our gas inventory to the lower of cost or market. Current liabilities decreased $136.1 million as a result of a decrease of $87.6 million in accounts payable and 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 and resulted in a payment of approximately $62.1 million in principal and accrued interest on May 1, 2009.

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. The Company 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. Demand fees collected under gas sales contracts by our E&P subsidiaries are included as part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in 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 June 30, 2009. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At June 30, 2009, we had $870.8 million of total debt with an average interest rate of 6.05%. Our revolving credit facility has a floating interest rate (1.192% at June 30, 2009). At June 30, 2009, we had $196.0 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 have any interest rate swaps in effect currently.

Commodities Risk

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

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any 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 June 30, 2009, the fair value of our financial instruments related to natural gas production was a $402.8 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 June 30, 2009 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2009	39.0	8.30				156.3
2010	36.0	9.04				105.9
Costless Collars:						
2009	27.0		8.61	11.36		110.5
2010	14.0		8.29	10.57		34.4
Basis Swaps:						
2009	40.2				(0.40)	(1.1)
2010	39.3				(0.36)	(2.7)
2011	9.0				(0.35)	(0.5)

At June 30, 2009, we had outstanding fixed-price basis differential swaps on 40.2 Bcf of 2009, 39.3 Bcf of 2010 and 9.0 Bcf of 2011 gas production that did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gas and oil sales. For the six months ended June 30, 2009, we recorded an unrealized loss of $6.1 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized gain of less than $0.1 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. As of July 27, 2009, we have basis protected an additional 13.9 Bcf of future gas production subsequent to June 30, 2009.

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 June 30, 2009, our Midstream Services segment had outstanding fair value hedges in place on 0.1 Bcf and 0.2 Bcf of gas for 2009 and 2010, 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 July 2009 through December 2010 and have a net fair value liability of $1.4 million as of June 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 June 30, 2009. There were no changes in our internal control over financial reporting during the three months ended June 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.

The following risk factors supplement the Company s risk factors as disclosed in Item 1A of Part I of the Company s Annual Report on Form 10-K:

Delays in the construction of the pipelines serving the Fayetteville Shale play or in the receipt of regulatory approvals affecting the pipelines could result in capacity constraints that may limit our ability to sell natural gas and/or receive favorable prices for our gas.

If drilling in the Fayetteville Shale continues to be successful, the amount of gas being produced in the area from new wells, as well as gas produced from existing wells, may exceed the capacity of the various intrastate or interstate transportation pipelines currently available. We have subscribed for capacity on the Fayetteville and Greenville Laterals recently built by Texas Gas Transmission, LLC, a subsidiary of Boardwalk Pipeline Partners, LP, or Texas

Gas, to service the Fayetteville Shale play area. We have also entered into a precedent agreement with Fayetteville

Express Pipeline LLC, which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P., with respect to another pipeline for the Fayetteville Shale play, which subject to regulatory approval is expected to be in service in late 2010 or early 2011.

On April 1, 2009, Texas Gas placed in service the entire Fayetteville-Greenville Expansion project and since then Texas Gas has reduced the capacity on, or shut down, the Fayetteville Lateral on several occasions due to various activities, including maintenance and pipeline inspection. In connection with the pipeline inspection, and in order to operate the laterals at the intended capacities, Texas Gas has entered into a Special Permit Modification Agreement with the Pipelines and Hazardous Materials Safety Administration authority (PHMSA), which prescribes a protocol to increase the interim pressure on each lateral to 72 % of specified minimum yield strength. Texas Gas has advised that the timing of pipeline shutdowns and the speed at which pipeline pressures can be increased to 72 % and 80 % subject to the agreement with the PHMSA . Based upon Texas Gas best estimates and subject to change in accordance with testing results and compliance with the rules, regulations and requirements of PHMSA , the timing of the pipeline work could range from one to five months on various segments of the laterals . As of July 10, 2009, Texas Gas indicated that it planned to begin remediating anomalies on the Fayetteville header, potentially as early as September 2009 . Texas Gas also indicated that it will attempt to schedule the repairs on the Fayetteville Lateral from Bald Knob, Arkansas to Lula, Mississippi and the Greenville Lateral in a manner that will maximize the amount of gas that can flow .

We rely upon the Fayetteville and Greenville Laterals to service our increased production from the Fayetteville Shale play. There can be no assurance that the amount of gas being produced in the Fayetteville Shale will not exceed the available capacity of the various intrastate or interstate transportation pipelines. Our projections, financial condition, results of operation and planned capital expenditures could be adversely impacted by lack of available capacity and continued capacity reductions, shutdowns or other curtailments of the laterals or other pipelines.

Our financial condition and results of operation could be adversely affected if the exemption for hydraulic fracturing is removed from the Safe Drinking Water Act, or if legislation is enacted at the state and local level regulating hydraulic fracturing.

We utilize hydraulic fracturing in connection with certain of our E&P operations. The fracturing fluids we use in our hydraulic fracturing operations in the Fayetteville Shale are comprised of over 99% water, with small quantities of additives containing compounds such as hydrochloric acid, mineral oil, citric acid and biocide. Many of these additives can be found in common consumer and household products. The fracturing fluid is injected under high pressure into the target formation. As the mixture is forced into the formation, the pressure causes the rock to fracture and the sand remains behind to prop open the fractures. These fractures create a pathway for the gas to flow out of the formation and into the wellbore. A 2004 study conducted by the EPA found that certain hydraulic fracturing posed no risk to drinking water and Congress exempted hydraulic fracturing from the Safe Drinking Water Act. Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the Safe Drinking Water Act or to enact legislation at the state and local government levels that would regulate the impact of hydraulic fracturing on drinking water supply. We are actively exploring and/or testing new alternatives for certain of the compounds we use in our additives but there can be no assurance that these alternatives will be effective at the volumes and rates we require. If the exemption for hydraulic fracturing is removed from the Safe Drinking Water Act, or if legislation is enacted at the state and local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operation.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

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

The Company held its Annual Meeting of Shareholders on May 19, 2009, for the purpose of electing Directors of the Company for the ensuing year and to ratify the appointment of PricewaterhouseCoopers LLP to serve as the Company s independent registered public accounting firm for 2009. Holders of 305,072,709 shares (88.78% of total outstanding shares) voted in total.

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

	Voted For	Withheld
Lewis E. Epley, Jr.	220,163,390	84,909,319
Robert L. Howard	151,425,656	153,647,053
Harold M. Korell	223,528,027	81,544,682
Vello A. Kuuskraa	154,349,666	150,723,043
Kenneth R. Mourton	151,383,707	153,689,002
Charles E. Scharlau	223,227,841	81,844,868

Holders of 304,730,038 shares voted for the proposal to ratify the appointment of PricewaterhouseCoopers LLP to serve as the Company s independent registered public accounting firm for 2009, 186,721 shares voted against and 155,950 shares abstained.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(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:	July 30, 2009	/s/ GREG D. KERLEY Greg D. Kerley Executive Vice President and Chief Financial Officer