SOUTHWESTERN ENERGY CO
Form 10-Q
April 29, 2010

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 **March 31, 2010**

Or

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities

Exchange Act of 1934

For the transition period from __________ to __________

Commission file number: **1-08246**

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware

71-0205415

(State or other jurisdiction of incorporation or organization)

(I.R.S. Employer Identification No.)

2350 North Sam Houston Parkway East, Suite 125, Houston, Texas

77032

(Address of principal executive offices)

(Zip Code)

(281) 618-4700

(Registrant s telephone number, including area code)

Not Applicable

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x 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 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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 April 27, 2010

Common Stock, Par Value $0.01

346,192,352

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2010

PART I FINANCIAL INFORMATION

PART II OTHER INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as anticipate, project, intend, estimate, expect, believe, predict, budget, projection, goal, plan, forecast, 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:

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play overall as well as relative to other productive shale gas plays;

•

our ability to fund our planned capital investments;

•

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

•

the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives;

•

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

•

our future property acquisition or divestiture activities;

•

the effects of weather;

•

increased competition;

•

the financial impact of accounting regulations and critical accounting policies;

•

the comparative cost of alternative fuels;

•

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

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

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

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, the risk of failure of exploration programs in areas in which oil or natural gas has not previously been discovered or produced, 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, 2009 (the 2009 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	
	March 31,	
	2010	2009
	(in thousands, except share/per share amounts)	
Operating Revenues:		

Gas sales	$ 479,411	$ 372,658
Gas marketing	157,673	151,572
Oil sales	3,462	1,182
Gas gathering	25,373	16,563
Other	2,198	(1,158)
	668,117	540,817
Operating Costs and Expenses:		

Gas purchases midstream services	157,668	149,180
Operating expenses	36,566	27,172
General and administrative expenses	32,944	23,709
Depreciation, depletion and amortization	139,017	124,228
Impairment of natural gas and oil properties		

907,812

Taxes, other than income taxes

13,832

9,208

380,027

1,241,309

Operating Income (Loss)

288,090

(700,492)

Interest Expense:

Interest on debt

13,929

14,185

Other interest charges

439

659

Interest capitalized

(7,860)

(11,160)

6,508

3,684

Other Income

23

365

Income (Loss) Before Income Taxes

281,605

(703,811)

Provision (Benefit) for Income Taxes:

Current	
	(35,500)
Deferred	109,837
	(235,459)
	109,837
	(270,959)
Net income (loss)	171,768
	(432,852)
Less: net loss attributable to noncontrolling interest	(29)
	(22)
Net Income (Loss) Attributable to Southwestern Energy	

	$	171,797
	$	(432,830)
Earnings Per Share:		
Net income (loss) attributable to Southwestern Energy stockholders - Basic		
	$	0.50
	$	(1.26)
Net income (loss) attributable to Southwestern Energy stockholders - Diluted		
	$	0.49
	$	(1.26)

Weighted Average Common Shares Outstanding:	
Basic	
	345,099,247
	342,570,995
Diluted	
	349,397,997
	342,570,995

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)

	March 31,	December 31,
	2010	2009
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents		

	$ 13,900	$ 13,184
Accounts receivable	269,534	263,076
Inventories	24,220	30,009
Hedging asset	194,721	163,069
Other	69,385	95,163
Total current assets	571,760	564,501

Property and Equipment:		
Gas and oil properties, using the full cost method, including $630.5 million in 2010 and $595.4 million in 2009 excluded from amortization	6,801,571	6,388,022
Gathering systems	595,604	547,637
Other	232,047	218,362
Total property and equipment	7,629,222	

	7,154,021
Less: Accumulated depreciation, depletion and amortization	
	3,166,714
	3,026,768
	4,462,508
	4,127,253
Other Assets	
	97,966
	78,496
TOTAL ASSETS	
	$ 5,132,234
	$ 4,770,250

LIABILITIES AND EQUITY

Current Liabilities:		
Short-term debt	$ 1,200	$ 1,200
Accounts payable	430,463	404,695
Taxes payable	27,506	25,500
Interest payable	9,847	19,775
Advances from partners	56,820	

	52,406
Hedging liability	11,847
	20,052
Current deferred income taxes	68,560
Other	11,814
	12,788
Total current liabilities	618,057
	536,416
Long-Term Debt	1,017,800

997,500

Other Liabilities:

Deferred income taxes	859,171	811,902
Long-term hedging liability	2,380	3,057
Pension and other postretirement liabilities	14,607	12,630
Other long-term liabilities	67,834	

67,764

943,992

895,353

Commitments and Contingencies

Equity:

Southwestern Energy stockholders equity

Common stock, $0.01 par value; authorized

540,000,000 shares, issued 346,192,064 shares in 2010 and 346,081,210 in 2009	3,462	3,461
Additional paid-in capital	837,751	833,494
Retained earnings	1,586,124	1,414,327
Accumulated other comprehensive income	119,778	84,276
Common stock in treasury, 206,604 shares in 2010 and 203,830 in 2009	(4,457)	(4,333)
Total Southwestern		

Energy stockholders equity	2,542,658	2,331,225
Noncontrolling interest	9,727	9,756
Total equity	2,552,385	2,340,981
TOTAL LIABILITIES AND EQUITY	$ 5,132,234	$ 4,770,250

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 three months ended

March 31,

2010

2009

(in thousands)

Cash Flows From Operating

Activities

Net income (loss)	$ 171,768	$ (432,852)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	139,419	124,647
Impairment of natural gas and oil properties		907,812
Deferred income taxes		

109,837

(235,459)

Other

(3,259)

8,407

Change in assets and liabilities:

Accounts receivable

(6,458)

44,723

Inventories

11,230

(2,099)

Accounts payable

(8,078)

9,930

Taxes payable

2,006

(11,952)

Interest payable

(9,928)

(9,200)

Advances from partners

4,414

33,479

Other assets and liabilities

6,628

(30,141)

Net cash provided by operating activities

417,579

407,295

Cash Flows From Investing Activities

Capital investments	(442,122)	(480,483)
Other	649	(4,370)
Net cash used in investing activities	(441,473)	(484,853)

Cash Flows From Financing Activities

Payments on

revolving long-term debt	(621,600)	
Borrowings under revolving long-term debt	641,900	
Change in bank drafts outstanding	4,057	(36,400)
Proceeds from exercise of common stock options	253	3
Net cash provided by (used in) financing activities	24,610	(36,397)

Increase (decrease) in cash and cash equivalents	716	(113,955)
Cash and cash equivalents at beginning of year	13,184	196,277
Cash and cash equivalents at end of period	$ 13,900	$ 82,322

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

Accumulated

Common Stock

Additional

Other

Common

Shares

Paid-In

Retained

Comprehensive

Stock in

Noncontrolling

Issued

Amount

Capital

Earnings

Income

Treasury

Interest

Total

(in thousands)

Balance at December 31, 2009
346,081
$ 3,461
$ 833,494
$ 1,414,327
$ 84,276
$ (4,333)
$ 9,756

$ 2,340,981

Comprehensive income:

Net income

171,797

(29)

171,768

Change in
derivatives

35,311

35,311

Change in pension

and other postretirement liabilities

191

191

Total comprehensive income

(29)

207,270

Stock-based compensation

4,005

4,005

Exercise of stock options

110

1

252

253

Issuance of restricted stock

6

Cancellation of restricted stock

(5)

Treasury stock
non-qualified plan

(124)

(124)

Balance at March 31, 2010

346,192

$ 3,462

$ 837,751

$ 1,586,124

$ 119,778

$ (4,457)

$ 9,727

$ 2,552,385

See the accompanying notes which are an integral part of these

unaudited condensed consolidated financial statements.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE

INCOME (LOSS)

(Unaudited)

	For the three months ended March 31,	
	2010	2009
	(in thousands)	
Net income (loss)	$ 171,768	$ (432,852)
Change in derivatives:		

Reclassification to earnings [1]	(29,301)	(84,553)
Ineffectiveness [2]	(57)	(719)
Change in fair value of derivative instruments [3]	64,669	169,962
Total change in derivatives	35,311	84,690

Change in pension and other postretirement liabilities [4]	191	196
Comprehensive income (loss)	207,270	(347,966)
Less: comprehensive income (loss) attributable to the noncontrolling interest	(29)	(22)

	Comprehensive income (loss) attributable to Southwestern Energy
	$ 207,299
	$ (347,944)

(1) Net of ($20.8) and ($53.6) million in taxes for the three months ended March 31, 2010 and 2009, respectively.

(2) Net of less than ($0.1) and ($0.5) million in taxes for the three months ended March 31, 2010 and 2009, respectively.

(3) Net of $46.0 and $107.8 million in taxes for the three months ended March 31, 2010 and 2009, respectively.

(4) Net of $0.1 and $0.1 million in taxes for the three months ended March 31, 2010 and 2009, 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 AND NEW ACCOUNTING STANDARDS

Southwestern Energy Company (including its subsidiaries, collectively, the Company, Southwestern Energy, we, u
its and our) is an independent energy company primarily focused on the exploration and production of natural gas. The Company engages in natural gas and oil exploration and production (E&P) and natural gas gathering and marketing (Midstream Services) through its subsidiaries. Southwestern Energy s current E&P operations are principally focused on the development of an unconventional natural gas play in Arkansas. The Company also is actively engaged in E&P activities in Oklahoma, Pennsylvania and Texas and intends to begin an exploration program in New Brunswick, Canada in 2010. Southwestern Energy s Midstream Services business is concentrated in the core areas of its E&P operations in the United States.

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 Securities and Exchange Commission. 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 statement 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, 2009 (2009 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 in the Notes to the Consolidated Financial Statements included in the Company s 2009 Annual Report on Form 10-K. The Company evaluates subsequent events through the date the financial statements are issued.

On January 1, 2010, the Company implemented certain provisions of Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) Topic 810, Consolidation. The new provisions (a) require a qualitative rather than a quantitative approach to determining the primary beneficiary of a variable interest entity (VIE); (b) amend certain guidance pertaining to the determination of the primary beneficiary when related parties are involved; (c) amend certain guidance for determining whether an entity is a VIE; and (d) require continuous assessments of whether an enterprise is the primary beneficiary of a VIE. The implementation did not have an impact on the Company s results of operations or financial condition.

On January 1, 2010, the Company implemented certain provisions of Accounting Standards Update No. 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements (Update 2010-06). Update 2010-06 requires the Company to (a) provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy; (b) provide a reconciliation of purchases, sales, issuance, and settlements of financial instruments valued with a Level 3 method; and (c) provide fair value measurement disclosures for each class of financial assets and liabilities. The implementation did not have an impact on the Company s results of operations or financial condition. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective for the Company beginning on January 1, 2011 and the Company does not expect the implementation to have a material impact on the Company s results of operations or financial condition.

Certain reclassifications have been made to the prior year s financial statements to conform to the 2010 presentation. The effects of the reclassifications were not material to the Company s unaudited condensed consolidated financial statements.

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(2) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of March 31, 2010 and December 31, 2009 consisted of the following:

	2010	2009
	(in thousands)	
Prepaid drilling costs	$ 46,988	$ 53,819
Prepaid insurance	4,303	6,572
Total	$ 51,291	$ 60,391

(3) INVENTORY

Inventory recorded in current assets includes $3.8 million at March 31, 2010 and $9.2 million at December 31, 2009, for gas in underground storage owned by the Company s E&P segment, and $20.4 million at March 31, 2010 and $20.8 million at December 31, 2009, for tubulars and other equipment used in the E&P segment.

The Company has one natural gas storage facility. The current portion of the gas is classified in inventory and carried at the lower of cost or market. During the first three months of 2009, the Company recorded a $4.3 million non-cash impairment to reduce the current portion of the Company s natural gas inventory to 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 whenever events or changes in circumstances indicate that it may not be recoverable. Withdrawals of current gas in underground storage are accounted for by a weighted average cost method whereby gas withdrawn from storage is relieved at the weighted average cost of current gas remaining in the facility.

Other Assets include $26.7 million at March 31, 2010 and $31.2 million at December 31, 2009 for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale play.

Tubulars and other equipment are carried at the lower of cost or market and are accounted for by 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 class.

(4)

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 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 average price for the first-day-of-the-month during the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average price for the first-day-of the-month during the previous 12 months for Henry Hub natural gas of $3.99 per MMBtu and $66.13 per barrel for West Texas Intermediate oil, adjusted for market differentials and the impact of derivatives qualifying as cash flow hedges, the Company s net book value of natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at March 31, 2010. Cash flow hedges of gas production in place increased the ceiling value by approximately $166.0 million at March 31, 2010. Excluding the benefit of those cash flow hedges at March 31, 2010, unamortized costs would have exceeded the ceiling value by $106.5 million. Decreases in market prices as well as changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

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At March 31, 2009, the ceiling value of the Company s reserves was calculated based upon the March 31, 2009 quoted market prices of $3.63 per Mcf for Henry Hub natural gas and $46.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. At March 31, 2009, the net capitalized costs of our gas and oil properties exceeded the ceiling by approximately $558.3 million (net of tax) and resulted in a non-cash ceiling test impairment in the first quarter of 2009.

(5)

EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three months ended March 31, 2010 and 2009:

	For the three months ended
	March 31,

	2010	2009
Net income (loss) attributable to Southwestern Energy (in thousands)	$ 171,797	$ (432,830)
Number of common shares:		
Weighted average outstanding	345,099,247	

342,570,995

Issued upon assumed exercise of outstanding stock options

4,014,914

Effect of issuance of nonvested restricted common stock

283,836

Weighted average and potential dilutive outstanding (1)

349,397,997

342,570,995

Earnings per share:

Net income (loss) attributable to Southwestern Energy stockholders basic	$	0.50
	$	(1.26)
Net income (loss) attributable to Southwestern Energy stockholders diluted	$	0.49
	$	(1.26)

(1)

Options for 448,933 shares and 4,698 shares of restricted stock were excluded from the calculation for the three months ended March 31, 2010 because they would have had an antidilutive effect. Due to the net loss for the three months ended March 31, 2009, options for 6,475,824 shares and 306,614 shares of restricted stock were antidilutive and excluded from the calculation.

(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 March 31, 2010 and December 31, 2009, 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

Arrangements that 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

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

GAAP requires that all derivatives be recognized in the balance sheet as either an asset or liability and be measured at fair value. Under GAAP, certain criteria must be satisfied in order for derivative financial instruments to be classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative s gains and losses to be recorded either in earnings or as a component of other comprehensive income. Gains and losses

on derivatives that are not elected for hedge accounting treatment or that do not meet hedge accounting requirements are recorded in earnings.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy at the time the transactions are entered into and the Company closely monitors the credit ratings of these counterparties. Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, the events in the financial markets in recent years demonstrate there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The balance sheet classification of the assets related to derivative financial instruments are summarized below at March 31, 2010 and December 31, 2009:

Derivative Assets				
	March 31, 2010		December 31, 2009	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value

(in thousands)	
Derivatives designated as hedging instruments:	
Fixed and floating price swaps	
Hedging asset	
	$ 140,559
Hedging asset	
	$ 117,553
Costless-collars	

Hedging asset	54,162
Hedging asset	45,516
Fixed and floating price swaps	
Other Assets	30,559
Other Assets	11,756
Costless-collars	
Other Assets	5,537
Other Assets	

Total derivatives designated as hedging instruments		
	$	230,817
	$	174,825

Derivatives not designated as hedging instruments:

Basis swaps

Hedging asset

$

Hedging asset

$

Basis swaps

Other Assets	21
Other Assets	
Total derivatives not designated as hedging instruments	$ 21

$

Total derivative assets

$ 230,838

$ 174,825

Derivative Liabilities

March 31, 2010

December 31, 2009

Balance Sheet Classification

Fair Value

Balance Sheet Classification

Fair Value

(in thousands)

Derivatives designated as hedging instruments:

Fixed and floating price swaps		
Hedging liability	$	2,064
Hedging liability	$	940
Costless-collars		
Hedging liability		1,162
Hedging liability		7,387

Fixed and floating price swaps
Long-term hedging liability
837
Long-term hedging liability
1,373
Costless-collars
Long-term hedging liability
1,543
Long-term hedging liability

Total derivatives designated as hedging instruments	
$	5,606
$	9,700

Derivatives not designated as hedging instruments:

Basis swaps

Hedging liability

$ 8,621

Hedging liability

$ 11,725

Basis swaps

Long-term hedging liability

Long-term hedging liability	1,684
Total derivatives not designated as hedging instruments	$ 8,621
	$ 13,409

Total derivative liabilities
$ 14,227
$ 23,109

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 instruments 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 March 31, 2010, the Company had cash flow hedges on the following volumes of natural gas production (in Bcf):

Year:	Fixed price swaps	Costless-collars
2010	27.0	21.0
2011	30.0	7.3

As of March 31, 2010, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $130.6 million. These amounts are net of a deferred income tax liability recorded as of March 31, 2010 of $83.5 million. The amount recorded in accumulated 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 March 31, 2010 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $111.7 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 $50.1 million for the three-month period ended March 31, 2010 compared to a realized gain of $141.5 million during the three-month period ended March 31, 2009. Volatility in earnings and other comprehensive income may occur in the future as a result of the application of the Company s derivative activities.

The following tables summarize the before tax effect of all cash flow hedges on the unaudited condensed consolidated financial statements for the three months ended March 31, 2010 and 2009:

Derivative Instrument	Gain (Loss) Recognized in Other Comprehensive Income (Effective Portion) 2010	2009
	(in thousands)	
Fixed price swaps	$ 75,314	

$ 224,992

Costless-collars

$ 35,317

$ 118,598

Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income

into Earnings

Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings

(Effective Portion)

Derivative Instrument

(Effective Portion)

	2010	2009
	(in thousands)	
Fixed price swaps		
Gas Sales	$ 33,673	$ 53,414
Costless-collars		

Gas Sales

$ 16,453

$ 88,043

Classification of Gain (Loss) Recognized in Earnings

Gain (Loss) Recognized

in Earnings

(Ineffective Portion)

Derivative Instrument

(Ineffective Portion)

2010

2009

		(in thousands)	
Fixed price swaps	Gas Sales	$ 473	$ 365
Costless-collars	Gas Sales	$ (375)	$ 48

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Fair Value Hedges

For fair value hedges, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately. As of March 31, 2010 and December 31, 2009, the Company had no material fair value hedges.

Other Derivative Contracts

Although the Company s basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company s derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. Basis swap derivative instruments that do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under hedging assets, other assets and hedging liabilities, and all realized and unrealized gains and losses related to these contracts are recognized immediately in the unaudited condensed consolidated statements of operations as a component of gas sales.

As of March 31, 2010, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 33.0 Bcf and 12.0 Bcf in 2010 and 2011, respectively.

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 March 31, 2010 and 2009:

	Income Statement Classification

Unrealized
Gain (Loss)
Recognized in
Earnings

Realized Gain
(Loss)
Recognized in
Earnings

Derivative
Instrument

of Gain (Loss)

2010

2009

2010

2009

(in thousands)

Basis swaps
Gas Sales
$ 4,810
$ (641)
$ (4,844)
$ 2,863

13

(7)

FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company s financial instruments as of March 31, 2010 and December 31, 2009 were as follows:

March 31,

2010

December 31,

2009

Carrying

Fair

Carrying

Fair

Amount

Value

Amount

Value

(in thousands)

Cash and cash equivalents

$ 13,900

$ 13,900

$ 13,184

$ 13,184

Total debt

$ 1,019,000

$ 1,075,606

$ 998,700

$ 1,031,826

Derivative instruments

$ 216,611

$ 216,611

$ 151,716

$ 151,716

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

Debt: The fair values of the Company s 7.5% Senior Notes due 2018, 7.35% Senior Notes due 2017, 7.125% Senior Notes due 2017 and 7.15% Senior Notes due 2018 were based on the market for the Company s publicly-traded debt as determined based on yield of the Company s 7.5% Senior Notes due 2018, which was 6.1% at March 31, 2010 and 6.7% at December 31, 2009. Borrowings under the Company s unsecured revolving credit facility of $344.8 million at March 31, 2010 and $324.5 million at December 31, 2009 approximate fair value.

Derivative Instruments: The fair value of all derivative 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.

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

Level 1 valuations -

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

Level 2 valuations -

Consist of quoted market information for the calculation of fair market value.

Level 3 valuations -

Consist of internal estimates and have the lowest priority.

Pursuant to GAAP, the Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company s Level 2 fair value measurements include fixed-price and floating-price swaps and are estimated using internal discounted cash flow calculations using the NYMEX futures index. The Company s Level 3 fair value measurements include costless-collars and basis swaps. The Company s costless-collars are valued using the Black-Scholes model, an industry standard option valuation model, and takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company s basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in thousands):

March 31, 2010

Fair Value
Measurements Using:

Quoted Prices

Significant

in Active

Other

Significant

Markets

Observable Inputs

Unobservable Inputs

Assets (Liabilities)

(Level 1)

(Level 2)

(Level 3)

at Fair Value

Derivative assets

$

$ 171,118

$ 59,720

$ 230,838

Derivative liabilities

(2,901)

(11,326)

(14,227)

Total

$

$ 168,217

$ 48,394

$ 216,611

December 31, 2009

Fair Value
Measurements Using:

Quoted Prices

Significant

in Active

Other

Significant

Markets

Observable Inputs

Unobservable Inputs

Assets (Liabilities)

(Level 1)

(Level 2)

			(Level 3)
			at Fair Value
Derivative assets	$	$ 129,309	$ 45,516
			$ 174,825
Derivative liabilities			
			(2,313)
			(20,796)
			(23,109)
Total	$	$ 126,996	$ 24,720

	$ 151,716

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-month period ended March 31, 2010. 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 the Company s judgment, reflect the assumptions a marketplace participant would have used at March 31, 2010.

	For the three months ended March 31, 2010
	(in thousands)
Balance at beginning of period	$ 24,720
Total gains or losses (realized/unrealized):	
Included in earnings	16,044
Included in other comprehensive income (loss)	19,239
Purchases, issuances, and settlements	

		(11,609)
Transfers into/out of Level 3		
Balance at end of period	$	48,394
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of March 31, 2010	$	4,435

(8)

DEBT

The components of debt as of March 31, 2010 and December 31, 2009 consisted of the following:

March 31,

December 31,

	2010
	2009
	(in thousands)
Short-term debt:	
7.15% Senior Notes due 2018	
$ 1,200	
$ 1,200	
Long-term debt:	

Variable rate (1.296% at March 31, 2010) unsecured revolving credit facility	344,800	324,500
7.5% Senior Notes due 2018	600,000	600,000
7.35% Senior Notes due 2017	15,000	15,000
7.125% Senior Notes due 2017	25,000	25,000
7.15% Senior Notes due 2018	33,000	33,000

		1,017,800
		997,500
Total debt	$	1,019,000
	$	998,700

Senior Notes and Subsidiary Guarantees

The indentures governing the Company s senior notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries ability to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets. All of the Company s senior notes are guaranteed by its subsidiaries SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services Company (SES). These guarantees may be unconditionally released in certain circumstances. All of these guarantees are currently in place. Please refer to Note 15, Condensed Consolidating Financial Information for additional information.

Credit Facility

On February 9, 2007, the Company amended its unsecured revolving credit facility (as further amended, the Credit Facility) with a syndicate of banks for which JPMorgan Chase Bank acts as the Administrative Agent. The Credit Facility expires in February 2012 and has a borrowing capacity of $1.0 billion, which may be increased to up to $1.25 billion at any time upon the Company s agreement with its existing or additional lenders. The interest rate on the Credit Facility is calculated based upon the Company s debt rating and is currently 87.5 basis points over the current London Interbank Offered Rate (LIBOR).

The Credit Facility is currently guaranteed by the Company s subsidiaries, SEECO, SEPCO and SES and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The Credit Facility also contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company must keep total debt (as defined in the Credit Facility) at or below 60% of its total capital (as defined in the Credit Facility), must maintain a certain level of stockholders equity (as defined in the Credit Facility), and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (as defined in the Credit Facility) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company s subsidiaries to incur debt. At March 31, 2010, the Company was in compliance with the covenants of its debt agreements. The credit status of the financial institutions participating in the Company s Credit Facility could adversely impact its ability to borrow funds under the facility. While the Company believes all of the lenders under the Credit Facility have the ability to provide funds, it cannot predict whether each lender will be able to meet its obligation under the facility.

(9) CONTINGENCIES AND COMMITMENTS

Commitments

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately CDN $47 million in the aggregate over the next three years. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of CDN $44.5 million. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company intends to begin the exploration program in 2010 and, as of March 31, 2010, no liability has been recognized in connection with the promissory notes.

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.

(10) INTEREST AND INCOME TAXES

Interest payments of $23.9 million and $23.4 million were made for the three months ended March 31, 2010 and 2009, respectively. No federal income tax payments were made for the three months ended March 31, 2010 and 2009.

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(11) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has defined pension and postretirement benefit plans which cover substantially all of the Company s employees. Net periodic pension and other postretirement benefit costs include the following components for the three months ended March 31, 2010 and 2009:

	Pension Benefits	
	For the three months ended March 31,	
	2010	2009
	(in thousands)	
Service cost	$ 1,774	$ 1,287
Interest cost	812	718
Expected return		

on plan assets	(876)	(702)
Amortization of prior service cost	86	83
Amortization of net loss	202	212
Net periodic benefit cost	$ 1,998	$ 1,598

Other Postretirement Benefits

For the three months ended

March 31,

	2010	2009
	(in thousands)	
Service cost	$ 272	$ 174
Interest cost	49	34
Amortization of transition obligation	16	16
Amortization of prior service cost	4	

		3
Amortization of net loss		
		5
		2
Net periodic benefit cost		
	$	346
	$	229

The Company currently expects to contribute $9.6 million to the pension plans and $0.1 million to the postretirement benefit plan in 2010. As of March 31, 2010, there have been no contributions to the pension plans and the postretirement benefit plan.

The Company maintains a non-qualified deferred compensation 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 and totaled 206,604 shares at March 31, 2010 compared to 203,830 shares at December 31, 2009.

(12)

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

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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.

On February 24, 2010, the Company's Board of Directors approved, and the Company and Computershare Trust Company, N.A., as rights agent, entered into, an amendment to the Rights Agreement pursuant to which the final expiration date of the rights (each as defined in the Rights Agreement) was advanced from April 8, 2019 to February 26, 2010. As a result of the amendment, the rights are no longer outstanding or exercisable.

(13)

STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three months ended March 31, 2010 and 2009:

	For the three months ended March 31,	
	2010	2009
	(in thousands)	
Stock-based compensation cost general and administrative expense	$ 2,297	$ 2,152
Stock-based compensation cost capitalized	1,708	1,511

As of March 31, 2010, there was $33.5 million of total unrecognized compensation cost related to the Company s unvested stock option and restricted stock grants. This cost is expected to be recognized over a weighted-average period of 2.7 years.

The following table summarizes stock option activity for the first three months of 2010 and provides information for options outstanding as of March 31, 2010.

Weighted

Average

Number

Exercise

of Options

Price

Outstanding at December 31, 2009	5,649,233	$ 11.59
Granted	30,915	44.65
Exercised	(110,319)	2.30
Forfeited or expired	(4,317)	35.89
Outstanding at March 31, 2010	5,565,512	$ 11.94
Exercisable at March 31, 2010	4,717,941	

	$	7.66

The following table summarizes restricted stock activity for the three months ended March 31, 2010 and provides information for unvested shares as of March 31, 2010.

	Weighted Average Number Grant Date of Shares Fair Value

Unvested shares at December 31, 2009	794,529	$ 33.70
Granted	8,670	43.98
Vested	(46,346)	28.10
Forfeited	(5,325)	35.05
Unvested shares at March 31, 2010	751,528	$ 34.16

19

(14)

SEGMENT INFORMATION

The Company s reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced gas volumes and through gathering fees associated with the transportation of natural gas to market.

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 2009 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes, for the purpose of reconciling the operating income (loss) amount shown below to consolidated income before income taxes, is the sum of operating income (loss), interest expense and interest and other income (loss). The Other column includes items not related to the Company s reportable segments including real estate and corporate items.

Exploration

And

Midstream

Production

Services

Other

Total

(in thousands)

Three months ended March 31, 2010:

Revenues from external customers	
	$ 485,071
	$ 183,046
	$
	$ 668,117
Intersegment revenues	
	6,998
	448,597
	246
	455,841
Operating income	
	250,431
	37,624
	35

288,090

Interest and other income (loss) (1)

(45)

68

23

Depreciation, depletion and amortization expense

132,707

6,161

149

139,017

Interest expense (1)

2,300

4,208

6,508

Provision for income taxes (1)

96,765

13,059

13

109,837

Assets

4,245,617

(2)

772,040

114,577

(3)

5,132,234

Capital investments (4)

411,433

49,266

12,926

473,625

Exploration

And

Midstream

	Production
	Services
	Other
	Total
	(in thousands)
Three months ended March 31, 2009:	
Revenues from external customers	$ 372,562

$ 168,135

$ 120

$ 540,817

Intersegment revenues

5,523

225,339

112

230,974

Operating income (loss)

(727,893)

(5)

27,362

39

(700,492)

Interest and other income[1]

363

2

365

Depreciation, depletion and amortization expense

120,131

3,926

171

124,228

Impairment of natural gas and oil properties

907,812

907,812

Interest expense (1)

3,243

441

3,684

Provision (benefit) for income taxes [1]

(281,339)

10,365

15

(270,959)

Assets

3,506,323

[2]

525,331

196,922

[3]

4,228,576

Capital investments

(4)	
	450,403
	50,921
	1,868
	503,192

(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)

Includes capital investments for office, technology, drilling rigs and other ancillary equipment not directly related to gas and oil property acquisition, exploration and development activities.

(3)

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

(4)

Capital investments include increases of $27.3 million and $23.6 million for the three months ended March 31, 2010 and 2009, respectively, relating to the change in accrued expenditures between periods.

(5)

The operating loss for the E&P segment for the three months ended March 31, 2009 includes a $907.8 million non-cash ceiling test impairment of our natural gas and oil properties resulting from a significant decline in natural gas prices from December 31, 2008 to March 31, 2009.

Included in intersegment revenues of the Midstream Services segment are $405.9 million and $196.0 million for the three months ended March 31, 2010 and 2009, respectively, for marketing of the Company s E&P sales. 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 currently located within the United States. The Company intends to begin an exploration program in New Brunswick, Canada in 2010.

(15)

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 7.35% Senior Notes and 7.125% Senior Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated to any future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors.

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

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(Unaudited)

Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated

(in thousands)

Three months ended March 31, 2010:

Operating revenues

$

$ 642,827

$ 67,322

$ (42,032)

$ 668,117

Operating costs and expenses:

Gas purchases
midstream services

158,016

(348)

157,668

Operating expenses

58,159

19,845

(41,438)

36,566

General and administrative expenses

28,125

5,065

(246)

32,944

Depreciation, depletion and amortization

132,375

6,642

139,017

Taxes, other than income taxes

12,589

1,243

13,832

Total operating costs and expenses

389,264

32,795

(42,032)

380,027

Operating income

253,563

34,527

288,090

Other income (loss)

(47)

70

23

Equity in earnings of subsidiaries

171,797

(171,797)

Interest expense

2,874

3,634

6,508

Income (loss) before income taxes

171,797

250,642

30,963

(171,797)

281,605

Provision for income taxes

97,761

12,076

109,837

Net income (loss)

171,797

152,881

18,887

(171,797)

171,768

Less: Net loss attributable to noncontrolling interest

(29)

(29)

Net income (loss) attributable to Southwestern Energy

$	171,797
$	152,910
$	18,887
$	(171,797)
$	171,797

Three months ended March 31, 2009:

Operating revenues	$	$ 524,829	$ 43,053	$ (27,065)	$ 540,817
Operating costs and expenses:					

Gas purchases midstream services

149,246

(66)

149,180

Operating expenses

40,880

13,179

(26,887)

27,172

General and administrative expenses

20,820

3,001

(112)

23,709

Depreciation, depletion and amortization

119,786

4,442

124,228

Impairment of natural gas and oil properties

907,812

907,812

Taxes, other than income taxes

8,450

758

9,208

Total operating costs and expenses

1,246,994

21,380

(27,065)

1,241,309

Operating income (loss)

(722,165)

21,673

(700,492)

Other income

361

4

365

Equity in earnings of subsidiaries

(432,830)

432,830

Interest expense

2,949

735

3,684

Income (loss) before income taxes

(432,830)

(724,753)

20,942

432,830

(703,811)

Provision (benefit) for income taxes

(279,020)

8,061

(270,959)

Net income (loss)

(432,830)

(445,733)

12,881

432,830

(432,852)

Less: Net loss attributable to noncontrolling

interest	
	(22)
	(22)
Net income (loss) attributable to Southwestern Energy	
	$ (432,830)
	$ (445,711)
	$ 12,881
	$ 432,830
	$ (432,830)

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CONDENSED CONSOLIDATING BALANCE SHEETS

(Unaudited)

Parent

Guarantors

Non- Guarantors

Eliminations

Consolidated

(in thousands)

March 31, 2010:

ASSETS

Cash and cash equivalents		
$	13,706	
$	27	
$	167	
$		
$	13,900	
Accounts receivable		
	390	
	253,844	
	15,300	
	269,534	
Inventories		

23,455

765

24,220

Other

13,347

248,946

1,813

264,106

Total current assets

27,443

526,272

18,045

571,760

Intercompany receivables

1,714,053

(1,256,013)

(443,184)

(14,856)

Investments

10,746

(10,745)

(1)

Property and equipment

89,056

6,816,804

723,362

7,629,222

Accumulated depreciation, depletion and amortization

(43,685)

(3,048,659)

(74,370)

(3,166,714)

45,371

3,768,145

648,992

4,462,508

Investments in subsidiaries (equity method)

1,832,713

(1,832,713)

Other assets

19,687

44,466

33,813

97,966

Total assets

$ 3,639,267

$ 3,093,616

$ 246,921

$ (1,847,570)

$ 5,132,234

LIABILITIES AND EQUITY

Accounts and notes payable
$ 120,037
$ 339,021
$ 24,815
$ (14,857)
$ 469,016

Other current liabilities

2,962

144,185

1,894

149,041

Total current liabilities

122,999

483,206

26,709

(14,857)

618,057

Long-term debt

1,017,800

1,017,800

Deferred income taxes

(91,298)

851,300

99,169

859,171

Other liabilities

37,381

43,257

4,183

84,821

Total liabilities

1,086,882

1,377,763

130,061

(14,857)

2,579,849

Commitments and contingencies

Total equity

2,552,385

1,715,853

	116,860
	(1,832,713)
	2,552,385
Total liabilities and equity	
	$ 3,639,267
	$ 3,093,616
	$ 246,921
	$ (1,847,570)
	$ 5,132,234

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CONDENSED CONSOLIDATING BALANCE SHEETS

(Unaudited)

Parent

Guarantors

Non- Guarantors

Eliminations

Consolidated

(in thousands)

December 31, 2009:

ASSETS

Cash and cash equivalents		
	$	7,378
	$	5,776
	$	30
	$	
	$	13,184
Accounts receivable		
		1,158

247,139

14,779

263,076

Inventories

29,156

853

30,009

Other

11,510

204,131

42,591

258,232

Total current assets

20,046

486,202

58,253

564,501

Intercompany receivables

1,751,398

(1,260,932)

(474,575)

(15,891)

Investments

10,746

(10,745)

(1)

Property and equipment

78,733

6,401,531

673,757

7,154,021

Accumulated depreciation, depletion and amortization

(41,658)

(2,919,403)

(65,707)

(3,026,768)

37,075

3,482,128

608,050

4,127,253

Investments in subsidiaries (equity method)

1,625,645

(1,625,645)

Other assets	
	20,161
	20,043
	38,292
	78,496
Total assets	
	$ 3,454,325
	$ 2,738,187
	$ 219,275
	$ (1,641,537)
	$ 4,770,250

LIABILITIES AND EQUITY

Accounts and notes payable	
$	149,485
$	293,176
$	24,401
$	(15,892)
$	451,170
Other current liabilities	
	2,937
	80,462
	1,847
	85,246
Total current liabilities	
	152,422
	373,638

	26,248
	(15,892)
	536,416
Long-term debt	
	997,500
	997,500
Deferred income taxes	
	(75,222)
	796,640
	90,484

811,902

Other liabilities

38,644

40,265

4,542

83,451

Total liabilities

1,113,344

1,210,543

121,274

(15,892)

2,429,269

Commitments and contingencies

Total equity	
	2,340,981
	1,527,644
	98,001
	(1,625,645)
	2,340,981
Total liabilities and equity	
	$ 3,454,325
	$ 2,738,187
	$ 219,275
	$ (1,641,537)

$ 4,770,250

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

(Unaudited)

Parent

Guarantors

Non-Guarantors

Eliminations

Consolidated

(in thousands)

<u>Three months ended March 31, 2010:</u>

Net cash provided by (used in) operating activities	$ (51,556)	$ 388,384	$ 80,751	$	$ 417,579
Investing activities:					
Capital investments	(9,874)				

	(380,221)
	(52,027)
	(442,122)
Other	
	3,292
	(5,902)
	3,259
	649
Net cash used in investing activities	
	(6,582)
	(386,123)
	(48,768)

(441,473)

Financing activities:

Intercompany activities

39,856

(8,010)

(31,846)

Payments on revolving long-term debt

(621,600)

	(621,600)
Borrowings under revolving long-term debt	641,900
	641,900
Other items	4,310
	4,310
Net cash provided by (used in) financing activities	

64,466

(8,010)

(31,846)

24,610

Increase (decrease) in cash and cash equivalents

6,328

(5,749)

137

716

Cash and cash equivalents at beginning of year

7,378

5,776

30

		13,184
Cash and cash equivalents at end of period		
	$	13,706
	$	27
	$	167
	$	
	$	13,900

Three months ended March 31, 2009:

Net cash provided by operating activities		
	$	31,055
	$	361,094
	$	15,146
	$	

	$ 407,295
Investing activities:	
Capital investments	
	(2,946)
	(426,019)
	(51,518)
	(480,483)
Other	
	1,822
	(7,139)

947

(4,370)

Net cash used in investing activities

(1,124)

(433,158)

(50,571)

(484,853)

Financing activities:

Intercompany activities

	(107,364)
	72,064
	35,300
Other items	
	(36,397)
	(36,397)
Net cash provided by (used in) financing activities	
	(143,761)
	72,064
	35,300

	(36,397)
Decrease in cash and cash equivalents	(113,830)
	(125)
	(113,955)
Cash and cash equivalents at beginning of year	195,969
	308
	196,277
Cash and cash equivalents at end of period	$ 82,139

$		
	$	183
$		
	$	82,322

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 2009 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three month periods ended March 31, 2010 and 2009. 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 2009 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 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 2009 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

Background

Southwestern Energy Company is an independent energy company engaged in natural gas and crude oil exploration, development and production (E&P). We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services.

Our primary business is the exploration for and production of natural gas within the United States with our current operations being principally focused on development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are also actively engaged in exploration and production activities in Oklahoma, Texas and Pennsylvania and recently announced a three year exploration program in New Brunswick, Canada that we intend to begin in 2010. We operate principally in two segments: E&P and Midstream Services.

We are focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. 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. We expect our natural gas volumes to continue to increase due to the ongoing development of our Fayetteville Shale play in Arkansas. The price we expect to receive for our natural gas is a critical factor in the capital investments we make in order to develop our properties and increase our production and significant, sustained declines in natural gas prices affects our ability to market natural gas on economically attractive terms to our customers. In recent years, there has been a significant decline in natural gas prices as evidenced by New York Mercantile Exchange (NYMEX) natural gas prices ranging from a high of $13.58 per Mcf in 2008 to a low of $2.51 per Mcf in 2009. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, 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 to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices.

Recent Financial and Operating Results

We reported net income attributable to Southwestern Energy of $171.8 million for the three months ended March 31, 2010, or $0.49 per diluted share, up from a net loss attributable to Southwestern Energy of $432.8 million, or $1.26 per diluted share, for the comparable period in 2009. The loss for the three months ended March 31, 2009 includes a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties resulting from a significant decline in natural gas prices from December 31, 2008 to March 31, 2009.

Our natural gas and oil production increased to 90.0 Bcfe for the three months ended March 31, 2010, up 41% from the three months ended March 31, 2009. The 26.1 Bcfe increase in our 2010 production was primarily due to a 25.3 Bcf increase in net production from our Fayetteville Shale play as a result of our ongoing development program. The

average price realized for our gas production, including the effects of hedges, decreased approximately 9% to $5.42 per Mcf for the three months ended March 31, 2010, as compared to the same period in 2009.

Our E&P segment reported operating income of $250.4 million for the three months ended March 31, 2010, up from an operating loss of $727.9 million for the three months ended March 31, 2009. The loss for the three months ended March 31, 2009 includes a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties. Excluding the $907.8 million non-cash ceiling test impairment, operating income increased primarily due to a $154.8 million increase in revenue resulting from higher production volumes which were partially offset by a $44.3 million decrease in revenues due to lower realized prices from the sale of our production and a $43.5 million increase in our operating costs and expenses.

Operating income for our Midstream Services segment was $37.6 million for the three months ended March 31, 2010, up from $27.4 million for the three months ended March 31, 2009, due to an increase of $24.2 million in gathering revenues which was partially offset by a decrease of $1.7 million in the margin generated from our natural gas marketing activities and a $12.3 million increase in operating costs and expenses, exclusive of gas purchase costs.

Net cash provided by operating activities increased 3% to $417.6 million for the three months ended March 31, 2010 compared to $407.3 million for the same period in 2009, due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher production volumes, partially offset by a decrease in changes in working capital. We had capital investments of $473.6 million for the three months ended March 31, 2010, of which $411.4 million was invested in our E&P segment compared to $503.2 million for the same period of 2009, of which $450.4 million was invested in our E&P segment.

Recent Developments

Production Guidance Update

As a result of operational and weather-related delays in our Fayetteville Shale play during the first quarter of 2010, we revised our previous expected gas and oil production range for 2010 from 400 to 410 Bcfe to 393 to 401 Bcfe, an increase of approximately 32% over 2009 levels (using midpoints). Of the 393 to 401 Bcfe of expected production in 2010, approximately 337 to 343 Bcf is expected to come from the Fayetteville Shale play.

First International Exploration Program

In the first quarter of 2010, we were awarded exclusive licenses to conduct an exploration program covering approximately 2.5 million acres in New Brunswick, Canada. We intend to begin this program, which is our first outside of the United States, in 2010. We are required to make certain capital investments totaling approximately CDN $47 million over the terms of the licenses, which are each three years. The 2010 capital investments for this program are included in New Ventures under our 2010 planned E&P investments. We refer you to Capital Investments and Financing Requirements below for a discussion of our capital investments.

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 and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

	For the three months ended March 31,	
	2010	2009
Revenues (in thousands)	$ 492,069	$ 378,085
Impairment of natural gas and oil properties (in thousands)	$	$ 907,812
Operating costs and		

expenses (in thousands)		
	$	241,638
	$	198,166
Operating income (loss) (in thousands)		
	$	250,431
	$	(727,893)
Gas production (MMcf)		
		89,689
		63,689
Oil production (MBbls)		
		46
		34
Total production (MMcfe)		
		89,964

		63,893
Average gas price per Mcf, including hedges		
	$	5.42
	$	5.94
Average gas price per Mcf, excluding hedges		
	$	4.87
	$	3.81
Average oil price per Bbl		
	$	75.55
	$	34.90
Average unit costs		

per Mcfe:		
Lease operating expenses	$	0.78
	$	0.78
General & administrative expenses	$	0.29
	$	0.31
Taxes, other than income taxes	$	0.14
	$	0.13
Full cost pool amortization	$	1.41
	$	1.82

Revenues

Revenues for our E&P segment were up $114.0 million, or 30%, for the three months ended March 31, 2010 compared to the same period in 2009. Higher natural gas production volumes in the first quarter of 2010 increased revenues by $154.4 million while lower realized prices for our gas production decreased revenue by $46.2 million. We expect our natural gas 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 April 28, 2010, we had hedged 48.0 Bcf of our remaining 2010 gas production, 92.1 Bcf of our 2011 gas production and 29.3 Bcf of our 2012 gas production to limit our exposure to price fluctuations. Additionally, as of April 28, 2010, we have outstanding fair value hedges in place on 3.9 Bcf, 0.9 Bcf and 4.3 Bcf of commitments for 2010, 2011 and 2012, respectively. These fair value hedges are a mixture of floating-price swap purchases and sales relating to our gas production. 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 March 31, 2010 was up approximately 41%, from the comparable period in 2009, to 90.0 Bcfe, due primarily to a 25.3 Bcf increase in net natural gas production from our Fayetteville Shale play as a result of our ongoing development program. Natural gas production represented nearly 100% of our total production for the three months ended March 31, 2010 and was up approximately 41% to 89.7 Bcf compared to the same period in 2009. Net production from the Fayetteville Shale was 75.5 Bcf for the three months ended March 31, 2010 compared to 50.2 Bcf for the same period in 2009.

Commodity Prices

The average price realized for our gas production, including the effects of hedges, decreased approximately 9% to $5.42 per Mcf for the three months ended March 31, 2010, as compared to the same period in 2009. The decrease in the average price realized reflects the decreased effect of our price hedging activities which more than offset higher average gas prices, excluding hedges, for the first three months of 2010 as compared to the same period in 2009. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 3 and Note 6 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion).

Our hedging activities increased the average gas price $0.55 per Mcf for the three months ended March 31, 2010 compared to an increase of $2.13 per Mcf for the same period in 2009. We had protected approximately 53% of our gas production for the three months ended March 31, 2010 from the impact of widening basis differentials through our hedging activities and sales arrangements. Disregarding the impact of hedges, the average price received for our gas production for the three months ended March 31, 2010 of $4.87 per Mcf was approximately $1.06 per Mcf higher than the three months ended March 31, 2009 and $0.43 lower than average NYMEX spot price, primarily due to locational market differentials. At March 31, 2010, we had basis protected on approximately 138 Bcf of our remaining 2010 expected gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX gas prices of approximately $0.10 per Mcf. Our E&P segment receives a sales price for our natural gas at a discount to NYMEX spot prices due to locational basis differentials, while transportation charges and fuel charges also reduce the price received. In 2010, we expect to pay average third-party transportation charges in the range of $0.25 to $0.32 per Mcf and average fuel charges in the range of 0.25% to 1.00% of transported volumes.

As of April 28, 2010, we had NYMEX fixed price hedges in place on notional volumes of 27.0 Bcf of our remaining 2010 gas production at an average price of $9.04 per MMBtu and collars in place on notional volumes of 21.0 Bcf of our remaining 2010 gas production at an average floor and ceiling price of $6.68 and $8.31 per MMBtu, respectively.

As of April 28, 2010, we had NYMEX fixed price hedges in place on notional volumes of 30.0 Bcf of our 2011 gas production and collars in place on notional volumes of 62.1 Bcf and 29.3 Bcf of our 2011 and 2012 gas production, respectively. Additionally, we have basis swaps on 33.0 Bcf for the remainder of 2010 and 12.0 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 increased to $250.4 million for the three months ended March 31, 2010 compared to an operating loss of $727.9 million for the same period in 2009. The loss for the three months ended March 31, 2009 includes a $907.8 million non-cash ceiling test impairment of our natural gas and oil properties resulting from a significant decline in natural gas prices from year-end 2008. Excluding the $907.8 million non-cash ceiling test impairment, operating income for the first three months of 2010 increased as a result of a 30% increase in revenues due to the growth in our production volumes which more than offset the decline in our average realized gas prices, including the effect of hedges, as well as a $43.5 million increase in operating costs and expenses resulting from our significant production growth.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.78 for both the three months ended March 31, 2010 and 2009.

General and administrative expenses per Mcfe were $0.29 for the three months ended March 31, 2010 compared to $0.31 for the same period in 2009, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $26.3 million for the three months ended March 31, 2010 compared to $19.7 million for the same period in 2009. Payroll, employee incentive compensation, and other employee-related costs increased by $4.8 million as a result of the expansion of our E&P operations in the Fayetteville Shale play.

Taxes other than income taxes per Mcfe increased to $0.14 for the three months ended March 31, 2010 compared to $0.13 for the same period in 2009. 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.

Our full cost pool amortization rate averaged $1.41 per Mcfe for the three months ended March 31, 2010 compared to $1.82 per Mcfe for the same period in 2009. The decline in the average amortization rate for the three months ended March 31, 2010 compared to the same period of 2009 was primarily the result of the $907.8 million non-cash ceiling test impairment recorded in the first quarter of 2009. 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 $630.5 million at March 31, 2010 compared to $595.4 million at December 31, 2009. The increase in unevaluated costs since December 31, 2009 primarily resulted from a $28.6 million increase in our undeveloped leasehold acreage and seismic costs.

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

	Midstream Services	
	For the three months ended March 31,	
	2010	2009
	(in thousands, except volumes)	
Revenues marketing	$ 564,988	$ 351,056
Revenues gathering		

	$	66,655
	$	42,418
Gas purchases marketing		
	$	560,003
	$	344,403
Operating costs and expenses		
	$	34,016
	$	21,709
Operating income		
	$	37,624
	$	27,362
Gas volumes marketed (Bcf)		
		107.9
		86.5
Gas volumes gathered (Bcf)		
		125.7
		79.5

Revenues

Revenues from our marketing activities were up 61% to $565.0 million for the three months ended March 31, 2010 compared to the same period in 2009. The increase in marketing revenues for the three months ended March 31, 2010 resulted from an increase in the volumes marketed and an increase in the prices received for volumes marketed. For the three months ended March 31, 2010, the volumes marketed increased 25% and the price received for volumes marketed increased 29% compared to the same period in 2009.

Revenues from our gathering activities were up 57% to $66.7 million for the three months ended March 31, 2010 compared to the same period in 2009. The increase in gathering revenues resulted from a 58% increase in the gas volumes gathered compared to the same period in 2009.

Of the total volumes marketed, production from our E&P operated wells accounted for 98% and 95% of the marketed volumes for the three months ended March 31, 2010 and 2009, 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 March 31, 2010 resulted from an increase 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 $10.3 million to $37.6 million for the three months ended March 31, 2010 due to an increase of $24.2 million in gathering revenues, which offset a decrease of $1.7 million in the margin generated from our natural gas marketing activities and a $12.3 million increase in operating costs and expenses, exclusive of purchased gas costs. The margin generated from natural gas marketing activities was $5.0 million for the three months ended March 31, 2010, compared to $6.7 million for the same period in 2009. Margins may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increase in volumes marketed for the three months ended March 31, 2010, as compared to the prior year period, resulted from the marketing of 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.

Interest Expense and Interest Income

Interest expense, net of capitalization, increased to $6.5 million for the three months ended March 31, 2010, compared to $3.7 million same period in 2009. We capitalized interest of $7.9 million for the three months ended March 31, 2010 compared to $11.2 million for the same period in 2009. The increase in interest expense, net of capitalization, was primarily due to the $3.3 million decrease in capitalized interest which resulted from our lower weighted average interest rate for the three months ended March 31, 2010 compared to the same period in 2009. Interest income for the three months ended March 31, 2010 was less than $0.1 million compared to $0.4 million for the same period in 2009 and is recorded in other income in the unaudited condensed consolidated statements of operations.

Income Taxes

Our effective tax rates were 39.0% and 38.5% for the three months ended March 31, 2010 and 2009, respectively. For the three months ended March 31, 2010, we recorded an income tax expense of $109.8 million compared to an income tax benefit of $271.0 million for the same period in 2009. The income tax benefit for the three months ended March 31, 2009 primarily resulted from the $907.8 million non-cash impairment of our gas and oil properties which was recorded in the three months ended March 31, 2009. We do not expect to be subject to current federal income taxes in 2010.

Stock-Based Compensation Expense

We recognized expense of $2.3 million and capitalized $1.7 million for stock-based compensation for the three months ended March 31, 2010 compared to $2.2 million expensed and $1.5 million capitalized for the comparable period in 2009. We refer you to Note 13 in the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion of our equity based compensation plans.

New Accounting Standards

On January 1, 2010, we implemented certain provisions of Financial Accounting Standards Board Accounting Standards Accounting Standards Codification (FASB ASC) Topic 810, Consolidation. The new provisions (a) require a qualitative rather than a quantitative approach to determining the primary beneficiary of a variable interest entity (VIE); (b) amend certain guidance pertaining to the determination of the primary beneficiary when related parties are involved; (c) amend certain guidance for determining whether an entity is a VIE; and (d) require continuous assessments of whether an enterprise is the primary beneficiary of a VIE. The implementation did not have an impact on our results of operations or financial condition.

On January 1, 2010, we implemented certain provisions of Accounting Standards Update No. 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements (Update 2010-06). Update 2010-06 requires us to (a) provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy; (b) provide a reconciliation of purchases, sales, issuance, and settlements of financial instruments valued with a Level 3 method; and (c) provide fair value measurement disclosures for each class of financial assets and liabilities. The implementation did not have an impact on our results of operations or financial condition. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective for us beginning on January 1, 2011 and we do not expect the implementation to have a material impact on our results of operations or financial condition.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our Credit Facility (we refer you to Note 8 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 to operate our businesses. 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, in increments or in the aggregate, to up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of March 31, 2010, we had borrowings of $344.8 million under our Credit Facility compared to $324.5 at December 31, 2009.

Net cash provided by operating activities increased 3% to $417.6 million for the three months ended March 31, 2010 compared to $407.3 million for the same period in 2009, due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher production volumes, partially offset by a decrease in changes in working capital. For the three months ended March 31, 2010, cash generated from our operating activities funded 94% of our cash requirements for capital investments with the balance funded through borrowings under our Credit Facility.

We believe that our operating cash flow and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for 2010. 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 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 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 are dependent 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 write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

Due to the above factors, 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 were $473.6 million for the three months ended March 31, 2010 compared to $503.2 million for the same period in 2009. Our E&P segment investments were $411.4 million for the three months ended March 31, 2010 compared to $450.4 million for the same period in 2009. Our E&P segment capitalized internal costs of $33.9 million for the three months ended March 31, 2010 compared to $24.1 million for the comparable period in 2009. 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 increase in internal costs capitalized is due to the addition of personnel and related costs in our exploration and development segment.

Although the remainder of our $2.1 billion capital investment program for 2010 is expected to be funded by cash flow from operations and borrowings from our Credit Facility, we may adjust the level of our investments dependent upon the level of cash flow generated from operations and our ability to borrow under our Credit Facility.

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Financing Requirements

Our total debt outstanding was $1,019.0 million at March 31, 2010 compared to $998.7 million at December 31, 2009. Our Credit Facility has a borrowing capacity of $1.0 billion, which may be increased, in increments or in the aggregate, to up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of March 31, 2010, we had $344.8 million outstanding under our Credit Facility with a weighted average interest rate of 1.296% compared to $324.5 million outstanding at December 31, 2009 with a weighted average interest rate of 1.106%. The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 87.5 basis points over LIBOR. Our publicly traded notes are rated BB+ by Standard and Poor s and we have a Corporate Family Rating of Ba2 by Moody s. Any downgrades in our public debt ratings could increase our cost of funds under the Credit Facility.

Our Credit Facility contains covenants which impose certain restrictions on us. Under the Credit Facility, we must keep our total debt at or below 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. Our Credit Facility s financial covenants with respect to capitalization percentages exclude the noncontrolling interest in equity, the effects of non-cash entries that result from any full cost ceiling impairments, hedging activities and our pension and other postretirement liabilities. Therefore, under our Credit Facility our capital structure at March 31, 2010 would have been 25% debt and 75% equity. We were also in compliance with all of the covenants of our Credit Facility at March 31, 2010. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our Credit Facility, we would have to decrease our capital investment plans.

At March 31, 2010, our capital structure consisted of 29% debt and 71% equity. Equity at March 31, 2010 includes a gain in accumulated other comprehensive gain of $130.6 million related to our hedging activities and a loss of $10.8 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on the current market value of our hedges at March 31, 2010 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 hedges allow us to ensure a certain level of cash flow to fund our operations. At April 28, 2010 we have hedged 48.0 Bcf of our remaining 2010 gas production, 92.1 Bcf of our expected 2011 gas production and 29.3 Bcf of our expected 2012 gas production. Additionally, as of April 28, 2010, we have outstanding fair value hedges in place on 3.9 Bcf, 0.9 Bcf and 4.3 Bcf of commitments for 2010, 2011 and 2012, respectively. These fair value hedges are a mixture of floating-price swap purchases and sales relating to our 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 2009 Annual Report on Form 10-K.

Contingent Liabilities and Commitments

In the first quarter of 2010, we were awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require us to make certain capital investments in New Brunswick of approximately CDN $47 million in the aggregate over the next three years. In order to obtain the licenses, we provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of CDN $44.5 million. The promissory notes secure our capital expenditure obligations under the licenses and are returnable to us to the extent we perform such obligations. If we fail to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. We intend to begin the exploration program in 2010 and, as of March 31, 2010, no liability has been recognized in connection with the promissory notes.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. We currently expect to contribute approximately $9.6 million to our pension plans and $0.1 million to our postretirement benefit plan in 2010. As of March 31, 2010, we have made no contributions to our pension plans and postretirement benefit plan. At March 31, 2010, we recognized a liability of $15.3 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $13.3 million at December 31, 2009.

In March of 2010, the President of the United States signed into law comprehensive health care reform legislation under the Patient Protection and Affordable Care Act (HR 3590) and the Health Care Education and Affordability Reconciliation Act (HR 4872) (the Acts). The Acts contain provisions which could impact our accounting for retiree medical benefits in future periods. However, the extent of that impact, if any, cannot be determined until regulations are promulgated under the Acts and additional interpretations of the Acts become available. Elements of the Acts, the impact of which are currently not determinable, include the elimination of lifetime limits on retiree medical coverage. Based on the analysis to date of the provisions in the Acts in which the impacts are reasonably determinable, a re-measurement of our Other Postretirement Benefits is not required at this time. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 11 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 our capital requirements through our Credit Facility described in Financing Requirements above. We had negative working capital of $46.3 million at March 31, 2010, and positive working capital of $28.1 million at December 31, 2009. Current assets increased by $7.3 million at March 31, 2010 compared to December 31, 2009, primarily due to a $31.7 million increase in our current hedging assets and partially offset by a $19.2 million decrease in our current deferred tax assets. Current liabilities increased by $81.6 million at March 31, 2010 compared to December 31, 2009 primarily as a result of a $68.6 million increase in our current deferred income taxes related to our hedging activities and a $25.8 million increase in accounts payable.

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 gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment s contractual commitments, especially during periods of colder weather. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. We recorded a $4.3 million non-cash natural gas inventory impairment charge for the three months ended March 31, 2009 to reduce the current portion of our natural gas inventory to the lower of cost or market. A 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 risk. Utilization of financial products for the reduction of interest rate risks is subject to the approval of our Board of Directors. 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 10% of accounts receivable at March 31, 2010. In addition, see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At March 31, 2010, we had $1,019.0 million of total debt with a weighted average interest rate of 5.38%. Our revolving credit facility has a floating interest rate (1.296% at March 31, 2010). At March 31, 2010, we had $344.8

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 volatility in the financial markets in recent years, 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 March 31, 2010, the fair value of our financial instruments related to natural gas production was a $215.7 million asset.

Weighted

Weighted

Weighted

Weighted

Average

Average

Average

Average

Fair value at

Price to be

Floor

Ceiling

Basis

March 31,

Swapped

Price

Price

Differential

2010

Volume

($/MMBtu)

($/MMBtu)

($/MMBtu)

($/MMBtu)

($ in millions)

Natural Gas (Bcf):

Fixed Price Swaps:

2010

27.0

9.04

128.7

2011

30.0

6.69

40.0

Floating Price Swaps:

2010

1.5

4.58

(0.9)

2012

4.3

5.69

(0.5)

Costless-Collars:

2010

21.0

6.68

8.31

51.7

2011

7.3

5.75

7.06

5.3

Basis Swaps:

2010

33.0

(0.34)

(6.9)

2011

12.0

(0.28)

(1.7)

At March 31, 2010, our basis swaps did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gas and oil sales. For the three months ended March 31, 2010, we recorded an unrealized gain of $4.8 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized gain of $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.

At December 31, 2009, we had outstanding natural gas price swaps on total notional volumes of 36.0 Bcf in 2010 and 30.0 Bcf in 2011 for which we will receive fixed prices ranging from $6.50 to $10.04 per MMBtu. At December 31, 2009, we had outstanding fixed price basis differential swaps on 46.5 Bcf of 2010 and 9.0 Bcf of 2011 gas production that did not qualify for hedge treatment.

At December 31, 2009, we had collars in place on notional volumes of 30.0 Bcf in 2010 at an average floor and ceiling price of $6.80 and $8.43 per MMBtu, respectively.

Midstream Services

At March 31, 2010, our Midstream Services segment had outstanding fair value hedges in place on 0.2 Bcf, 0.1 Bcf, 0.1 Bcf of gas for 2010, 2011 and 2012, respectively. These hedges are a mixture of floating-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from April 2010 through March 2012 and have a net fair value liability of $0.5 million as of March 31, 2010.

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 March 31, 2010. There were no changes in our internal control over financial reporting during the three months ended March 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

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

ITEM 1A. RISK FACTORS.

There were no additions or material changes to the Company s risk factors as disclosed in Item 1A of Part I in the Company s 2009 Annual Report on Form 10-K.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 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:

April 29, 2010

/s/ GREG D. KERLEY

Greg D. Kerley

Executive Vice President

and Chief Financial Officer