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

Form 10-Q

(Mark One)

[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **September 30, 2011**

Or

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

Commission file number: **1-08246**

Southwestern Energy Company
(Exact name of registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 North Sam Houston Parkway East, Suite 125, Houston, Texas	**77032**
(Address of principal executive offices)	(Zip Code)

(281) 618-4700
(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes☒ No☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes☒ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

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

Class	Outstanding as of October 25, 2011
Common Stock, Par Value $0.01	348,339,433

SOUTHWESTERN ENERGY COMPANY

INDEX TO FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED September 30, 2011

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- our ability to fund our planned capital investments;
- 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;
- 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, including pressure pumping equipment and crews;

- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- our future property acquisition or divestiture activities;
- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;
- 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, 2010 (the "2010 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q ("Form 10-Qs").

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-Q occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

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

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 551,757	$ 483,886	$ 1,543,667	$ 1,378,873
Gas marketing	176,787	161,324	549,243	461,576
Oil sales	2,157	3,238	7,387	10,320
Gas gathering	36,541	33,715	107,961	87,303
Other	13	9	498	2,160
	767,255	682,172	2,208,756	1,940,232
Operating Costs and Expenses:				
Gas purchases – midstream services	175,236	158,095	545,518	457,555
Operating expenses	63,911	52,929	175,763	140,438
General and administrative expenses	35,600	35,158	112,955	104,735
Depreciation, depletion and amortization	179,113	151,284	514,180	434,307
Taxes, other than income taxes	17,677	14,570	49,429	38,654
	471,537	412,036	1,397,845	1,175,689
Operating Income	295,718	270,136	810,911	764,543
Interest Expense:				
Interest on debt	16,696	14,574	48,380	42,702
Other interest charges	902	503	3,414	1,447
Interest capitalized	(11,941)	(8,488)	(32,531)	(24,872)
	5,657	6,589	19,263	19,277
Other Income (Loss), Net	(122)	326	321	265
Income Before Income Taxes	289,939	263,873	791,969	745,531
Provision for Income Taxes:				
Current	3,491	(5,274)	3,691	(2,574)
Deferred	111,275	108,509	309,042	293,690
	114,766	103,235	312,733	291,116
Net income	175,173	160,638	479,236	454,415
Less: Net loss attributable to noncontrolling interest	—	(103)	—	(192)
Net Income Attributable to Southwestern Energy	$ 175,173	$ 160,741	$ 479,236	$ 454,607
Earnings Per Share:				
Net income attributable to Southwestern Energy stockholders – Basic	$ 0.50	$ 0.47	$ 1.38	$ 1.32
Net income attributable to Southwestern Energy stockholders – Diluted	$ 0.50	$ 0.46	$ 1.37	$ 1.30
Weighted Average Common Shares Outstanding:				
Basic	347,239,793	345,587,569	347,070,330	345,326,985
Diluted	349,998,789	349,228,576	349,891,885	349,308,957

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

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

	September 30, 2011	December 31, 2010
ASSETS	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 13,293	$ 16,055
Restricted cash	69,261	—
Accounts receivable	346,896	351,573
Inventories	46,532	35,098
Hedging asset	315,546	130,412
Other	44,592	47,755
Total Current Assets	836,120	580,893
Property and Equipment:		
Gas and oil properties, using the full cost method, including $870.2 million in 2011 and $712.1 million in 2010 excluded from amortization	8,974,350	7,749,863
Gathering systems	958,105	817,465
Other	511,938	413,557
Total property and equipment	10,444,393	8,980,885
Less: Accumulated depreciation, depletion and amortization	4,230,121	3,682,688
	6,214,272	5,298,197
Other Assets	163,715	138,373
TOTAL ASSETS	$ 7,214,107	$ 6,017,463
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 1,200	$ 1,200
Accounts payable	487,186	473,890
Taxes payable	28,887	50,051
Interest payable	10,589	19,954
Advances from partners	96,274	81,705
Hedging liability	9,071	7,685
Current deferred income taxes	115,869	44,089
Other	17,174	15,409
Total Current Liabilities	766,250	693,983
Long-Term Debt	1,271,000	1,093,000
Other Liabilities:		
Deferred income taxes	1,461,205	1,130,292
Long-term hedging liability	4,582	40,188
Pension and other postretirement liabilities	13,629	15,777
Other long-term liabilities	88,888	79,347
	1,568,304	1,265,604
Commitments and Contingencies		
Equity:		
Southwestern Energy stockholders' equity		
Common stock, $0.01 par value; authorized 1,250,000,000 shares in 2011 and 2010; issued 348,264,799 shares in 2011 and 347,733,839 in 2010	3,483	3,477
Additional paid-in capital	880,425	862,423
Retained earnings	2,497,681	2,018,445
Accumulated other comprehensive income	229,750	83,975
Common stock in treasury, 125,984 shares in 2011 and 156,636 in 2010	(2,786)	(3,444)
Total Equity	3,608,553	2,964,876
TOTAL LIABILITIES AND EQUITY	$ 7,214,107	$ 6,017,463

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

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

	For the nine months ended September 30, 2011	2010
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 479,236	$ 454,415
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	516,891	435,515
Deferred income taxes	309,042	293,690
Unrealized gain (loss) on derivatives	905	(3,504)
Stock-based compensation	6,619	6,612
Other	(353)	(2,173)
Change in assets and liabilities:		
Accounts receivable	4,664	(34,313)
Inventories	(5,993)	8,157
Accounts payable	1,539	25,090
Taxes payable	(21,165)	(915)
Interest payable	(9,365)	(9,808)
Advances from partners	14,568	25,825
Other assets and liabilities	3,623	16,471
Net cash provided by operating activities	1,300,211	1,215,062
Cash Flows From Investing Activities		
Capital investments	(1,543,549)	(1,506,079)
Proceeds from sale of property and equipment	121,546	348,379
Transfers to restricted cash	(85,040)	(355,865)
Transfers from restricted cash	15,779	1,689
Other	4,940	(2,632)
Net cash used in investing activities	(1,486,324)	(1,514,508)
Cash Flows From Financing Activities		
Payments on current portion of long-term debt	(600)	(600)
Payments on revolving long-term debt	(2,575,000)	(2,043,600)
Borrowings under revolving long-term debt	2,753,600	2,336,100
Change in bank drafts outstanding	10,621	5,546
Revolving credit facility costs	(10,211)	—
Proceeds from exercise of common stock options	4,844	3,013
Net cash provided by financing activities	183,254	300,459
Effect of exchange rate changes on cash	97	—
Increase (decrease) in cash and cash equivalents	(2,762)	1,013
Cash and cash equivalents at beginning of year	16,055	13,184
Cash and cash equivalents at end of period	$ 13,293	$ 14,197

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)

	Common Stock		Additional		Accumulated Other	Common	
	Shares Issued	Amount	Paid-In Capital	Retained Earnings	Comprehensive Income	Stock in Treasury	Total
				(in thousands)			
Balance at December 31, 2010	347,734	$ 3,477	$ 862,423	$ 2,018,445	$ 83,975	$ (3,444)	$ 2,964,876
Comprehensive income:							
Net income	—	—	—	479,236	—	—	479,236
Change in derivatives	—	—	—	—	146,016	—	146,016
Change in pension and other postretirement liabilities	—	—	—	—	590	—	590
Currency translation adjustment	—	—	—	—	(831)	—	(831)
Total comprehensive income							625,011
Stock-based compensation	—	—	12,622	—	—	—	12,622
Exercise of stock options	563	6	4,838	—	—	—	4,844
Issuance of restricted stock	8	—	—	—	—	—	—
Cancellation of restricted stock	(40)	—	—	—	—	—	—
Treasury stock – non-qualified plan	—	—	542	—	—	658	1,200
Balance at September 30, 2011	348,265	$ 3,483	$ 880,425	$ 2,497,681	$ 229,750	$ (2,786)	$ 3,608,553

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

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

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Net income	$ 175,173	$ 160,638	$ 479,236	$ 454,415
Change in derivatives:				
Reclassification to earnings [1]	(49,436)	(49,919)	(113,850)	(117,461)
Ineffectiveness [2]	1,574	253	307	3,358
Change in fair value of derivative instruments [3]	170,251	97,975	259,559	184,260
Total change in derivatives	122,389	48,309	146,016	70,157
Change in pension and other postretirement liabilities [4]	197	191	590	573
Change in currency translation adjustment	(1,219)	—	(831)	—
Comprehensive income	296,540	209,138	625,011	525,145
Less: Comprehensive loss attributable to the noncontrolling interest	—	(103)	—	(192)
Comprehensive income attributable to Southwestern Energy	$ 296,540	$ 209,241	$ 625,011	$ 525,337

(1) Net of ($31.6), ($31.9), ($72.8) and ($77.2) million in taxes for the three months ended September 30, 2011 and 2010, and the nine months ended September 30, 2011 and 2010, respectively.

(2) Net of $1.0, $0.1, $0.2 and $2.1 million in taxes for the three months ended September 30, 2011 and 2010, and the nine months ended September 30, 2011 and 2010, respectively.

(3) Net of $108.8, $62.6, $165.9 and $122.4 million in taxes for the three months ended September 30, 2011 and 2010, and the nine months ended September 30, 2011 and 2010, respectively.

(4) Net of $0.2, $0.1, $0.4 and $0.3 million in taxes for the three months ended September 30, 2011 and 2010, and the nine months ended September 30, 2011 and 2010, respectively.

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

(1) BASIS OF PRESENTATION AND NEW ACCOUNTING STANDARDS

Southwestern Energy Company (including its subsidiaries, collectively, “Southwestern” or the “Company”) 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, natural gas gathering and natural gas marketing through its subsidiaries. Southwestern’s exploration, development and production (“E&P”) activities 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 Texas, Pennsylvania, Louisiana and, to a lesser extent, in Oklahoma. In 2010, the Company commenced an exploration program in New Brunswick, Canada, its first operations outside of the United States. Southwestern’s natural gas marketing and natural gas gathering businesses (“Midstream Services”) are located in the core areas of its E&P operations.

The accompanying unaudited condensed consolidated financial statements were prepared using accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information and in accordance with the rules and regulations of the 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 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, 2010 (“2010 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 2010 Annual Report on Form 10-K. The Company evaluates subsequent events through the date the financial statements are issued.

On January 1, 2011, 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 entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on the Company’s results of operations, financial position or cash flows.

(2) DIVESTITURE

In the second quarter of 2011, the Company sold certain oil and natural gas leases, wells and gathering equipment in Shelby, San Augustine, and Sabine Counties in East Texas for approximately $108.1 million, before customary purchase price adjustments. This divestiture included only the Haynesville and Middle Bossier Shale intervals in the affected acreage, which intervals had net production of approximately 7.0 MMcf per day as of May 25, 2011 and proved net reserves of approximately 25.1 Bcf at December 31, 2010. Under full cost accounting, this divestiture was accounted for as an adjustment of capitalized natural gas and oil properties with no gain recognized.

At closing, the Company deposited $85.0 million of proceeds from this sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. The remaining funds are classified as restricted cash in the unaudited condensed consolidated balance sheet and, unless utilized for one or more like-kind exchange transactions, are restricted in their use until November 2011. For the nine months ended September 30, 2011, the Company utilized $15.7 million of these restricted funds for like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code.

(3) PREPAID EXPENSES

The components of prepaid expenses included in other current assets as of September 30, 2011 and December 31, 2010 consisted of the following:

	September 30, 2011	December 31, 2010
	(in thousands)	
Prepaid drilling costs	$ 29,286	$ 21,997
Prepaid insurance	7,820	7,690
Total	$ 37,106	$ 29,687

(4) INVENTORY

Inventory recorded in current assets includes $10.8 million at September 30, 2011 and $10.0 million at December 31, 2010, for natural gas in underground storage owned by the Company's E&P segment, and $35.7 million at September 30, 2011 and $25.1 million at December 31, 2010, for tubulars and other equipment used in the E&P segment.

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

Other Assets include $18.0 million at September 30, 2011 and $20.6 million at December 31, 2010 for inventory held by the Midstream Services segment consisting primarily of pipe that will be used to construct gathering systems for the Fayetteville Shale and Marcellus Shale plays.

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.

(5) NATURAL 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 on a country by country basis and amortized 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. The average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, is used to calculate the ceiling value of reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.16 per MMBtu and $91.00 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 its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at September 30, 2011. Cash flow hedges of natural gas production in place increased the ceiling value by approximately $294.5 million at September 30, 2011. 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.

All of our costs directly associated with the acquisition and evaluation of properties in New Brunswick, Canada relating to our exploration program at September 30, 2011 were unproved and did not exceed the ceiling amount. If our exploration program in Canada is unsuccessful on all or a portion of these properties, a ceiling test impairment may result in the future.

(6) EARNINGS PER SHARE

The following table presents the computation of earnings per share for the three- and nine-month periods ended September 30, 2011 and 2010:

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
Net income attributable to Southwestern Energy (in thousands)	$ 175,173	$ 160,741	$ 479,236	$ 454,607
Number of common shares:				
Weighted average outstanding	347,239,793	345,587,569	347,070,330	345,326,985
Issued upon assumed exercise of outstanding stock options	2,490,783	3,438,923	2,591,687	3,747,293
Effect of issuance of nonvested restricted common stock	268,213	202,084	229,868	234,679
Weighted average and potential dilutive outstanding[1]	349,998,789	349,228,576	349,891,885	349,308,957
Earnings per share:				
Net income attributable to Southwestern Energy stockholders – basic	$ 0.50	$ 0.47	$ 1.38	$ 1.32
Net income attributable to Southwestern Energy stockholders – diluted	$ 0.50	$ 0.46	$ 1.37	$ 1.30

(1) Options for 783,823 shares and 5,645 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2011 because they would have had an antidilutive effect. Options for 907,284 shares and 59,153 shares of restricted stock were excluded from the calculation for the three months ended September 30, 2010 because they would have had an antidilutive effect. Options for 811,552 shares and 7,114 shares of restricted stock were excluded from the calculation for the nine months ended September 30, 2011 because they would have had an antidilutive effect. Options for 510,067 shares and 12,627 shares of restricted stock were excluded from the calculation for the nine months ended September 30, 2010 because they would have had an antidilutive effect.

(7) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to commodity price risk which impacts the predictability of its cash flows related to the sale of natural gas and oil. The primary risk managed by the Company's use of certain derivative financial instruments is commodity price risk. These derivative financial instruments allow the Company to limit its price exposure to a portion of its projected natural gas sales. At September 30, 2011 and December 31, 2010, 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 derivative financial instruments are summarized below at September 30, 2011 and December 31, 2010:

	Derivative Assets			
	September 30, 2011		December 31, 2010	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging asset	$ 213,334	Hedging asset	$ 81,797
Costless-collars	Hedging asset	101,988	Hedging asset	48,582
Fixed and floating price swaps	Other assets	72,797	Other assets	5,086
Costless-collars	Other assets	23,668	Other assets	72,827
Total derivatives designated as hedging instruments		$ 411,787		$ 208,292
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging asset	$ 224	Hedging asset	$ 33
Basis swaps	Other assets	558	Other assets	—
Total derivatives not designated as hedging instruments		$ 782		$ 33
Total derivative assets		$ 412,569		$ 208,325

	Derivative Liabilities			
	September 30, 2011		December 31, 2010	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Derivatives designated as hedging instruments:				
Fixed and floating price swaps	Hedging liability	$ 6,533	Hedging liability	$ 1,774
Costless-collars	Hedging liability	604	Hedging liability	3,903
Fixed and floating price swaps	Long-term hedging liability	2,507	Long-term hedging liability	22,334
Costless-collars	Long-term hedging liability	1,094	Long-term hedging liability	17,854
Total derivatives designated as hedging instruments		$ 10,738		$ 45,865
Derivatives not designated as hedging instruments:				
Basis swaps	Hedging liability	$ 1,934	Hedging liability	$ 2,008
Basis swaps	Long-term hedging liability	981	Long-term hedging liability	—
Total derivatives not designated as hedging instruments		$ 2,915		$ 2,008
Total derivative liabilities		$ 13,653		$ 47,873

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 September 30, 2011, the Company had cash flow hedges on the following volumes of natural gas production and gas in underground storage (in Bcf):

Year:	Fixed price swaps	Costless-collars
2011	64.7	15.6
2012	185.9	80.5
2013	185.2	—

As of September 30, 2011, the Company recorded a net gain in accumulated other comprehensive income related to its hedging activities of $242.5 million. This amount is net of a deferred income tax liability recorded as of September 30, 2011 of $155.0 million. The amount recorded in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Assuming the market prices of natural gas futures as of September 30, 2011 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $186.3 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 natural gas sales in the unaudited condensed consolidated statements of operations. Natural gas sales included a realized gain from settled contracts of $186.6 million for the nine-month period ended September 30, 2011 compared to a realized gain of $194.6 million for the nine-month period ended September 30, 2010. Volatility in earnings and other comprehensive income may occur in the future as a result 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- and nine-month periods ended September 30, 2011 and 2010.

	Gain Recognized in Other Comprehensive Income (Effective Portion)			
	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	2011	2010	2011	2010
	(in thousands)			
Fixed price swaps	$ 230,783	$ 75,864	$ 360,362	$ 166,398
Costless-collars	$ 48,315	$ 84,750	$ 65,144	$ 140,282

	Classification of Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument		2011	2010	2011	2010
		(in thousands)			
Fixed price swaps	Gas Sales	$ 67,125	$ 65,761	$ 145,662	$ 144,015
Costless-collars	Gas Sales	$ 13,918	$ 16,073	$ 40,978	$ 50,635

	Classification of Gain (Loss) Recognized in Earnings (Ineffective Portion)	Gain (Loss) Recognized in Earnings (Ineffective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument		2011	2010	2011	2010
		(in thousands)			
Fixed price swaps	Gas Sales	$ (1,754)	$ (258)	$ (755)	$ (3,924)
Costless-collars	Gas Sales	$ (826)	$ (157)	$ 252	$ (1,577)

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 September 30, 2011 and December 31, 2010, 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, as applicable, 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 natural gas sales.

As of September 30, 2011, the Company had basis swaps on natural gas production that did not qualify for hedge accounting treatment of 9.2 Bcf, 37.7 Bcf, 30.1 Bcf and 9.1 Bcf for 2011, 2012, 2013, and 2014, 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- and nine-month periods ended September 30, 2011 and 2010.

		Unrealized Gain (Loss) Recognized in Earnings			
	Income Statement Classification	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	of Unrealized Gain (Loss)	2011	2010	2011	2010
		(in thousands)			
Basis swaps	Gas Sales	$ (1,967)	$ 1,620	$ (159)	$ 9,496

		Realized Gain (Loss) Recognized in Earnings			
	Income Statement Classification	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	of Realized Gain (Loss)	2011	2010	2011	2010
		(in thousands)			
Basis swaps	Gas Sales	$ (22)	$ (2,580)	$ (2,377)	$ (9,811)

(8) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of September 30, 2011 and December 31, 2010 were as follows:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	$ 13,293	$ 13,293	$ 16,055	$ 16,055
Restricted cash	$ 69,261	$ 69,261	$ —	$ —
Unsecured revolving credit facility	$ 599,800	$ 599,800	$ 421,200	$ 421,200
Senior notes	$ 672,400	$ 774,915	$ 673,000	$ 761,372
Derivative instruments, net	$ 398,916	$ 398,916	$ 160,452	$ 160,452

The carrying values of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, other current assets and current liabilities on the 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 senior notes 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 4.7% at September 30, 2011 and 5.2% at December 31, 2010. The carrying values of the borrowings under the Company's unsecured revolving credit facility at September 30, 2011 and December 31, 2010 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):

	September 30, 2011			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$ —	$ 286,131	$ 126,438	$ 412,569
Derivative liabilities	—	(9,040)	(4,613)	(13,653)
Total	$ —	$ 277,091	$ 121,825	$ 398,916

	December 31, 2010			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Derivative assets	$ —	$ 86,883	$ 121,442	$ 208,325
Derivative liabilities	—	(24,108)	(23,765)	(47,873)
Total	$ —	$ 62,775	$ 97,677	$ 160,452

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three- and nine-month periods ended September 30, 2011. 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 September 30, 2011.

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Balance at beginning of period	$ 89,395	$ 53,566	$ 97,677	$ 24,720
Total gains or losses (realized/unrealized):				
Included in earnings	11,102	14,956	38,694	48,743
Included in other comprehensive income	35,223	68,834	23,913	91,224
Purchases, issuances, and settlements:				
Purchases	—	—	—	—
Issuances	—	—	—	—
Settlements	(13,895)	(13,493)	(38,601)	(40,824)
Transfers into/out of Level 3	—	—	142	—
Balance at end of period	$ 121,825	$ 123,863	$ 121,825	$ 123,863
Change in unrealized gain (loss) included in earnings relating to derivatives still held as of September 30	$ (2,793)	$ 1,463	$ 93	$ 7,919

(9) DEBT

The components of debt as of September 30, 2011 and December 31, 2010 consisted of the following:

	September 30, 2011	December 31, 2010
	(in thousands)	
Short-term debt:		
7.15% Senior Notes due 2018	$ 1,200	$ 1,200
Total short-term debt	1,200	1,200
Long-term debt:		
Variable rate (2.205% at September 30, 2011 and 0.887% at December 31, 2010) unsecured revolving credit facility	599,800	421,200
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	31,200	31,800
	1,271,000	1,093,000
Total debt	$ 1,272,200	$ 1,094,200

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 currently 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. Please refer to Note 16, "Condensed Consolidating Financial Information", for additional information.

Credit Facility

In February 2011, the Company amended and restated its unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016 ("Credit Facility"). The amount available under the Credit Facility may be increased to $2.0 billion at any time upon the Company's agreement with its existing or additional lenders. The interest rate on the amended credit facility is calculated based upon our debt rating and is currently 200 basis points over the current London Interbank Offered Rate (LIBOR) and was 200 basis points over LIBOR at September 30, 2011. The Credit Facility is guaranteed by the Company's subsidiary, SEECO. The Credit Facility requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. The terms of the Credit Facility also include covenants that restrict the ability of the Company and its material subsidiaries to merge, consolidate or sell all or substantially all of their assets, restrict the ability of the Company and its subsidiaries to incur liens and restrict the ability of the Company's subsidiaries to incur indebtedness. At September 30, 2011, the Company's capital structure consisted of 26% debt and 74% equity and it was in compliance with the covenants of its debt agreements. While the Company believes all of the lenders under the Credit Facility have the ability to provide funds, it cannot predict whether each will be able to meet its obligation under the facility.

(10) COMMITMENTS AND CONTINGENCIES

Commitments

During the first and second quarters of 2011, the Company's marketing subsidiary, Southwestern Energy Services Company ("SES"), entered into a number of short and long term firm transportation service and gathering agreements in support of the Company's growing Marcellus Shale operations in Pennsylvania and the Company has provided certain guarantees of a portion of SES's obligations under these agreements. In March 2011, SES entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which it will enter into short and long term firm natural gas transportation services on Millennium's existing system and expansions of the system expected to be in-service by late 2012 and late 2013. Certain of SES's obligations under the precedent agreement are subject to the satisfaction of conditions precedent. On June 30, 2011, SES entered into a long term agreement with Bluestone Gathering, a wholly owned subsidiary of DTE Energy Company, pursuant to which Bluestone Gathering will build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SES in support of a portion of the Company's future Marcellus Shale natural gas production. The projected in-service date for the gathering system is as early as the second quarter of 2012. SES also executed firm transportation agreements with Tennessee Gas Pipeline that increase the Company's ability to move its Marcellus Shale natural gas production in the short term to market as well as a precedent agreement for an expansion project with a projected in-service date of November 2013 pursuant to which SES has subscribed for 100,000 Dekatherm/day of capacity. As of September 30, 2011, SES's obligations for demand and similar charges under the firm transportation agreements totaled approximately $120.4 million and the Company currently has no guarantee obligations with respect to the firm transportation agreements and the gathering project and services.

On October 6, 2011, the Company's subsidiary, Southwestern Energy Production Company ("SEPCO"), entered into a 15-year agreement with a subsidiary of Boardwalk Pipeline Partners for the construction of a gathering system in Susquehanna and Lackawanna counties in Pennsylvania, which once constructed is expected to have a delivery capacity of 275,000 Dekatherm/day.

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 $47 million Canadian dollars ("CAD") in the aggregate over a three year period. 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 CAD $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 commenced its Canada exploration program in 2010 and, as of September 30, 2011, 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. Environmental and cleanup related costs of a non-capital nature are accrued 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

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273 rd District Court in Shelby County, Texas (collectively, the "Sixth Petition") plaintiff alleged that, in 2005, they provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiff's allegations in the Sixth Petition included various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 15, 2005 and February 15, 2006. In the Sixth Petition, plaintiff sought actual damages of over $55 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of $46 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. On December 31, 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. On February 11, 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. On March 11, 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. A hearing on the post-verdict motions was held on March 14, 2011. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred on April 6, 2011 and was unsuccessful. On June 6, 2011, SEPCO received by mail a letter dated June 2, 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. On July 5, 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response on July 11, 2011. On July 12, 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 12, 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 21, 2011 consistent with his findings in his June 2, 2011 letter and the disgorgement award. On August 24, 2011, a judgment was entered pursuant to which plaintiff and intervenor are entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees which currently are estimated to be up to $8.9 million and all costs of court of the plaintiff and intervenor. On September 22, 2011, the plaintiff and intervenor filed a motion to modify, correct or reform the judgment which requested that the court vacate the final judgment ordering SEPCO to produce additional accounting information and reconsider the amount SEPCO should disgorge. On September 23, 2011, SEPCO filed a motion for a new trial.

The Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $44.2 million, including interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

In March 2010, the Company's subsidiary, SEECO, Inc., was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefor and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

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

(11) INTEREST AND INCOME TAXES

The following table provides interest and income taxes paid for the three- and nine-month periods ended September 30, 2011 and 2010:

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Interest payments	$ 25,897	$ 24,560	$ 57,745	$ 52,510
Income tax payments	$ 3,391	$ 14,006	$ 20,391	$ 16,706

(12) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has defined pension and postretirement benefit plans which cover substantially all of the Company's employees. Net periodic pension and other postretirement benefit costs include the following components for the three- and nine-month periods ended September 30, 2011 and 2010:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Service cost	$ 2,330	$ 1,774	$ 6,992	$ 5,322
Interest cost	918	812	2,753	2,436
Expected return on plan assets	(1,099)	(876)	(3,298)	(2,628)
Amortization of prior service cost	86	87	258	260
Amortization of net loss	214	201	642	605
Net periodic benefit cost	$ 2,449	$ 1,998	$ 7,347	$ 5,995

	Postretirement Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Service cost	$ 338	$ 272	$ 1,015	$ 816
Interest cost	63	49	189	147
Amortization of transition obligation	16	16	48	48
Amortization of prior service cost	4	3	11	11
Amortization of net loss	2	6	8	16
Net periodic benefit cost	$ 423	$ 346	$ 1,271	$ 1,038

The Company currently expects to contribute $12.5 million to the pension plans and $0.1 million to the postretirement benefit plan in 2011. As of September 30, 2011, the Company has contributed $9.8 million to the pension plans and $0.1 million to the postretirement benefit plan during the year.

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 125,984 shares at September 30, 2011 compared to 156,636 shares at December 31, 2010.

(13) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and nine months ended September 30, 2011 and 2010:

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Stock-based compensation cost – general and administrative expense	$ 1,933	$ 2,179	$ 6,619	$ 6,612
Stock-based compensation cost – capitalized	$ 2,188	$ 1,699	$ 6,003	$ 5,096

As of September 30, 2011, there was $27.5 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 2.3 years.

The following table summarizes stock option activity for the first nine months of 2011 and provides information for options outstanding as of September 30, 2011.

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2010	4,769,122	$ 16.13
Granted	21,695	41.31
Exercised	(563,356)	8.60
Forfeited or expired	(25,538)	34.84
Outstanding at September 30, 2011	4,201,923	$ 17.16
Exercisable at September 30, 2011	3,416,457	$ 12.61

The following table summarizes restricted stock activity for the nine months ended September 30, 2011 and provides information for unvested shares as of September 30, 2011.

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at December 31, 2010	834,058	$ 36.24
Granted	4,965	38.35
Vested	(39,260)	38.10
Forfeited	(40,496)	36.47
Unvested shares at September 30, 2011	759,267	$ 36.15

(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 natural 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 2010 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 amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense and other income, (loss) net. The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration and Production		Midstream Services	Other		Total
	(in thousands)					
Three months ended September 30, 2011:						
Revenues from external customers	$ 553,913		$ 213,328	$ 14		$ 767,255
Intersegment revenues	1,707		530,503	818		533,028
Operating income	228,476		66,837	405		295,718
Other income (loss), net(1)	(17)		(109)	4		(122)
Depreciation, depletion and amortization expense	169,391		9,414	308		179,113
Interest expense(1)	2,003		3,654	—		5,657
Provision for income taxes(1)	89,811		24,791	164		114,766
Assets	5,827,527	(2)	1,116,333	270,247	(3)	7,214,107
Capital investments(4)	421,182		32,158	17,095		470,435
Three months ended September 30, 2010:						
Revenues from external customers	$ 487,133		$ 195,039	$ —		$ 682,172
Intersegment revenues	4,767		451,870	247		456,884
Operating income	216,696		53,390	50		270,136
Other income, net(1)	219		107	—		326
Depreciation, depletion and amortization expense	143,457		7,684	143		151,284
Interest expense(1)	1,701		4,888	—		6,589
Provision for income taxes(1)	84,257		18,957	21		103,235
Assets	4,572,128	(2)	910,506	510,090	(3)	5,992,724
Capital investments(4)	420,294		77,006	19,330		516,630

	Exploration and Production		Midstream Services	Other		Total
	(in thousands)					
Nine months ended September 30, 2011:						
Revenues from external customers	$ 1,551,538		$ 657,204	$ 14		$ 2,208,756
Intersegment revenues	10,120		1,526,504	2,387		1,539,011
Operating income	629,298		180,398	1,215		810,911
Other income (loss), net(1)	332		(28)	17		321
Depreciation, depletion and amortization expense	486,130		27,170	880		514,180
Interest expense(1)	5,706		13,557	—		19,263
Provision for income taxes(1)	246,685		65,560	488		312,733
Assets	5,827,527	(2)	1,116,333	270,247	(3)	7,214,107
Capital investments(4)	1,365,434		137,998	53,506		1,556,938
Nine months ended September 30, 2010:						
Revenues from external customers	$ 1,391,353		$ 548,879	$ —		$ 1,940,232
Intersegment revenues	14,471		1,288,531	739		1,303,741
Operating income	629,600		134,781	162		764,543
Other income, net(1)	67		186	12		265
Depreciation, depletion and amortization expense	413,069		20,831	407		434,307
Interest expense(1)	4,705		14,572	—		19,277
Provision for income taxes(1)	244,094		46,954	68		291,116
Assets	4,572,128	(2)	910,506	510,090	(3)	5,992,724
Capital investments(4)	1,272,953		216,025	44,802		1,533,780

(1) Interest income, interest expense and the provision 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 natural gas and oil property acquisition, exploration and development activities.
(3) Other assets represent corporate assets not allocated to segments and assets, including restricted cash and investments in cash equivalents, for non-reportable segments.
(4) Capital investments include reductions of $60.9 million and $29.8 million for the three-month periods ended September 30, 2011 and 2010, respectively, and reductions of $3.0 million and $4.8 million for the nine-month periods ended September 30, 2011 and 2010, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $459.4 million and $394.3 million for the three months ended September 30, 2011 and 2010, respectively, and $1,327.3 million and $1,135.3 million for the nine months ended September 30, 2011 and 2010, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, restricted cash, 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. For the three months ended September 30, 2011 and 2010, capital investments within the E&P segment include $8.3 million and $2.5 million, respectively, related to the Company's activities in Canada. For the nine months ended September 30, 2011 and 2010, capital investments within the E&P segment include $16.1 million and $9.8 million, respectively, related to the Company's activities in Canada. At September 30, 2011, assets include $25.6 million and at September 30, 2010, assets include $9.7 million related to the Company's activities in Canada.

(15) NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

On May 12, 2011, the FASB issued guidance on fair value measurement and disclosure requirements outlined in Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820)–Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* ("Update 2011-04"). Update 2011-04 expands existing fair value disclosure requirements, particularly for Level 3 inputs, including: quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs; the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed; and the use of a nonfinancial asset if it differs from the highest and best use assumed in the fair value measurement. The amendments in Update 2011-04 must be applied prospectively and are effective during interim and annual periods beginning after December 15, 2011. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated financial statements.

On June 16, 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* ("Update 2011-05"), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of 'other comprehensive income' ("OCI") in the statement of changes in stockholders' equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The implementation of these changes is not expected to have an impact on the Company's results of operations, financial position or cash flows.

(16) CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company is providing condensed consolidating financial information for SEECO, SEPCO and SES, its subsidiaries that are currently 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 September 30, 2011:					
Operating revenues	$ —	$ 730,826	$ 105,486	$ (69,057)	$ 767,255
Operating costs and expenses:					
Gas purchases – midstream services	—	175,729	—	(493)	175,236
Operating expenses	—	101,645	30,034	(67,768)	63,911
General and administrative expenses	—	34,030	2,366	(796)	35,600
Depreciation, depletion and amortization	—	169,446	9,667	—	179,113
Taxes, other than income taxes	—	13,731	3,946	—	17,677
Total operating costs and expenses	—	494,581	46,013	(69,057)	471,537
Operating income	—	236,245	59,473	—	295,718
Other loss, net	—	(16)	(106)	—	(122)
Equity in earnings of subsidiaries	175,173	—	—	(175,173)	—
Interest expense	—	2,376	3,281	—	5,657
Income (loss) before income taxes	175,173	233,853	56,086	(175,173)	289,939
Provision for income taxes	—	92,725	22,041	—	114,766
Net income (loss)	175,173	141,128	34,045	(175,173)	175,173
Less: Net loss attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to Southwestern Energy	$ 175,173	$ 141,128	$ 34,045	$ (175,173)	$ 175,173
Three months ended September 30, 2010:					
Operating revenues	$ —	$ 648,605	$ 85,602	$ (52,035)	$ 682,172
Operating costs and expenses:					
Gas purchases – midstream services	—	158,503	—	(408)	158,095
Operating expenses	—	78,113	26,197	(51,381)	52,929
General and administrative expenses	—	31,041	4,363	(246)	35,158
Depreciation, depletion and amortization	—	143,202	8,082	—	151,284
Taxes, other than income taxes	—	13,014	1,556	—	14,570
Total operating costs and expenses	—	423,873	40,198	(52,035)	412,036
Operating income	—	224,732	45,404	—	270,136
Other income, net	—	214	112	—	326
Equity in earnings of subsidiaries	160,741	—	—	(160,741)	—
Interest expense	—	1,716	4,873	—	6,589
Income (loss) before income taxes	160,741	223,230	40,643	(160,741)	263,873
Provision for income taxes	—	87,387	15,848	—	103,235
Net income (loss)	160,741	135,843	24,795	(160,741)	160,638
Less: Net loss attributable to noncontrolling interest	—	(103)	—	—	(103)
Net income (loss) attributable to Southwestern Energy	$ 160,741	$ 135,946	$ 24,795	$ (160,741)	$ 160,741

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Nine months ended September 30, 2011:					
Operating revenues	$ —	$ 2,101,099	$ 299,252	$ (191,595)	$ 2,208,756
Operating costs and expenses:					
Gas purchases – midstream services	—	546,731	—	(1,213)	545,518
Operating expenses	—	276,974	86,811	(188,022)	175,763
General and administrative expenses	—	101,372	13,943	(2,360)	112,955
Depreciation, depletion and amortization	—	485,546	28,634	—	514,180
Taxes, other than income taxes	—	41,206	8,223	—	49,429
Total operating costs and expenses	—	1,451,829	137,611	(191,595)	1,397,845
Operating income	—	649,270	161,641	—	810,911
Other income (loss), net	—	345	(24)	—	321
Equity in earnings of subsidiaries	479,236	—	—	(479,236)	—
Interest expense	—	7,769	11,494	—	19,263
Income (loss) before income taxes	479,236	641,846	150,123	(479,236)	791,969
Provision for income taxes	—	253,738	58,995	—	312,733
Net income (loss)	479,236	388,108	91,128	(479,236)	479,236
Less: Net loss attributable to noncontrolling interest	—	—	—	—	—
Net income (loss) attributable to Southwestern Energy	$ 479,236	$ 388,108	$ 91,128	$ (479,236)	$ 479,236
Nine months ended September 30, 2010:					
Operating revenues	$ —	$ 1,853,194	$ 227,625	$ (140,587)	$ 1,940,232
Operating costs and expenses:					
Gas purchases – midstream services	—	458,788	—	(1,233)	457,555
Operating expenses	—	211,252	67,801	(138,615)	140,438
General and administrative expenses	—	91,270	14,204	(739)	104,735
Depreciation, depletion and amortization	—	412,217	22,090	—	434,307
Taxes, other than income taxes	—	34,461	4,193	—	38,654
Total operating costs and expenses	—	1,207,988	108,288	(140,587)	1,175,689
Operating income	—	645,206	119,337	—	764,543
Other income, net	—	74	191	—	265
Equity in earnings of subsidiaries	454,607	—	—	(454,607)	—
Interest expense	—	5,526	13,751	—	19,277
Income (loss) before income taxes	454,607	639,754	105,777	(454,607)	745,531
Provision for income taxes	—	249,866	41,250	—	291,116
Net income (loss)	454,607	389,888	64,527	(454,607)	454,415
Less: Net loss attributable to noncontrolling interest	—	(192)	—	—	(192)
Net income (loss) attributable to Southwestern Energy	$ 454,607	$ 390,080	$ 64,527	$ (454,607)	$ 454,607

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
			(in thousands)		
September 30, 2011:					
ASSETS					
Cash and cash equivalents	$ 11,842	$ 1,451	$ —	$ —	$ 13,293
Restricted cash	69,261	—	—	—	69,261
Accounts receivable	273	322,217	24,406	—	346,896
Inventories	—	45,629	903	—	46,532
Other current assets	4,557	352,209	3,372	—	360,138
Total current assets	85,933	721,506	28,681	—	836,120
Intercompany receivables	1,853,309	34	24,961	(1,878,304)	—
Property and equipment	175,968	9,147,370	1,121,055	—	10,444,393
Less: Accumulated depreciation, depletion and amortization	63,301	4,042,935	123,885	—	4,230,121
	112,667	5,104,435	997,170	—	6,214,272
Investments in subsidiaries (equity method)	2,902,323	—	—	(2,902,323)	—
Other assets	23,995	117,782	21,938	—	163,715
Total assets	$ 4,978,227	$ 5,943,757	$ 1,072,750	$ (4,780,627)	$ 7,214,107
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 148,433	$ 334,144	$ 45,285	$ —	$ 527,862
Other current liabilities	3,531	232,632	2,225	—	238,388
Total current liabilities	151,964	566,776	47,510	—	766,250
Intercompany payable	—	1,394,690	483,614	(1,878,304)	—
Long-term debt	1,271,000	—	—	—	1,271,000
Deferred income taxes	(101,174)	1,339,822	222,557	—	1,461,205
Other liabilities	47,884	53,234	5,981	—	107,099
Total liabilities	1,369,674	3,354,522	759,662	(1,878,304)	3,605,554
Commitments and contingencies					
Total equity	3,608,553	2,589,235	313,088	(2,902,323)	3,608,553
Total liabilities and equity	$ 4,978,227	$ 5,943,757	$ 1,072,750	$ (4,780,627)	$ 7,214,107

CONDENSED CONSOLIDATING BALANCE SHEETS
(Unaudited)

	Parent	Guarantors	Non- Guarantors	Eliminations	Consolidated
			(in thousands)		
December 31, 2010:					
ASSETS					
Cash and cash equivalents	$ 8,381	$ 7,631	$ 43	$ —	$ 16,055
Accounts receivable	382	331,154	20,037	—	351,573
Inventories	—	34,263	835	—	35,098
Other current assets	5,015	171,060	2,092	—	178,167
Total current assets	13,778	544,108	23,007	—	580,893
Intercompany receivables	1,820,857	131	18,724	(1,839,712)	—
Investments	—	11,103	(11,102)	(1)	—
Property and equipment	124,823	7,871,279	984,783	—	8,980,885
Less: Accumulated depreciation, depletion and amortization	52,256	3,526,010	104,422	—	3,682,688
	72,567	4,345,269	880,361	—	5,298,197
Investments in subsidiaries (equity method)	2,253,871	—	—	(2,253,871)	—
Other assets	18,918	92,747	26,708	—	138,373
Total assets	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463
LIABILITIES AND EQUITY					
Accounts and notes payable	$ 175,476	$ 336,411	$ 33,208	$ —	$ 545,095
Other current liabilities	3,288	142,839	2,761	—	148,888
Total current liabilities	178,764	479,250	35,969	—	693,983
Intercompany payable	—	1,317,696	522,017	(1,839,713)	—
Long-term debt	1,093,000	—	—	—	1,093,000
Deferred income taxes	(98,206)	1,066,166	162,332	—	1,130,292
Other liabilities	41,557	89,986	3,769	—	135,312
Total liabilities	1,215,115	2,953,098	724,087	(1,839,713)	3,052,587
Commitments and contingencies					
Total equity	2,964,876	2,040,260	213,611	(2,253,871)	2,964,876
Total liabilities and equity	$ 4,179,991	$ 4,993,358	$ 937,698	$ (4,093,584)	$ 6,017,463

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Unaudited)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
			(in thousands)		
Nine months ended September 30, 2011:					
Net cash provided by (used in) operating activities	$ (23,901)	$ 1,146,062	$ 178,050	$ —	$ 1,300,211
Investing activities:					
Capital investments	(53,085)	(1,333,977)	(156,487)	—	(1,543,549)
Proceeds from sale of property and equipment	—	121,281	265	—	121,546
Transfers to restricted cash	(85,040)	—	—	—	(85,040)
Transfers from restricted cash	15,779	—	—	—	15,779
Other	11,046	(31,564)	25,458	—	4,940
Net cash used in investing activities	(111,300)	(1,244,260)	(130,764)	—	(1,486,324)
Financing activities:					
Intercompany activities	(44,592)	92,018	(47,426)	—	—
Payments on current portion of long-term debt	(600)	—	—	—	(600)
Payments on revolving long-term debt	(2,575,000)	—	—	—	(2,575,000)
Borrowings under revolving long-term debt	2,753,600	—	—	—	2,753,600
Other items	5,254	—	—	—	5,254
Net cash provided by (used in) financing activities	138,662	92,018	(47,426)	—	183,254
Effect of exchange rate changes on cash	—	—	97	—	97
Increase (decrease) in cash and cash equivalents	3,461	(6,180)	(43)	—	(2,762)
Cash and cash equivalents at beginning of year	8,381	7,631	43	—	16,055
Cash and cash equivalents at end of period	$ 11,842	$ 1,451	$ —	$ —	$ 13,293
Nine months ended September 30, 2010:					
Net cash provided by (used in) operating activities	$ (46,565)	$ 1,082,585	$ 179,042	$ —	$ 1,215,062
Investing activities:					
Capital investments	(33,915)	(1,231,500)	(240,664)	—	(1,506,079)
Proceeds from sale of property and equipment	—	347,150	1,229	—	348,379
Transfers to restricted cash	(355,865)	—	—	—	(355,865)
Transfers from restricted cash	1,689	—	—	—	1,689
Other	9,437	(18,440)	6,371	—	(2,632)
Net cash used in investing activities	(378,654)	(902,790)	(233,064)	—	(1,514,508)
Financing activities:					
Intercompany activities	130,114	(184,121)	54,007	—	—
Payments on current portion of long-term debt	(600)	—	—	—	(600)
Payments on revolving long-term debt	(2,043,600)	—	—	—	(2,043,600)
Borrowings under revolving long-term debt	2,336,100	—	—	—	2,336,100
Other items	8,559	—	—	—	8,559
Net cash provided by (used in) financing activities	430,573	(184,121)	54,007	—	300,459
Increase (decrease) in cash and cash equivalents	5,354	(4,326)	(15)	—	1,013
Cash and cash equivalents at beginning of year	7,378	5,776	30	—	13,184
Cash and cash equivalents at end of period	$ 12,732	$ 1,450	$ 15	$ —	$ 14,197

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 2010 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2011 and 2010. 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 2010 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 2010 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. We operate principally in two segments: E&P and 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 the 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 Texas, Pennsylvania, Louisiana and to a lesser extent in Oklahoma, and, in 2010, we commenced an exploration program in New Brunswick, Canada, which represents our first operations outside of the United States.

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 production volumes will continue to increase due to our ongoing development of the Fayetteville Shale play in Arkansas and the Marcellus Shale play in Pennsylvania. 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. 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.

Three Months Ended September 30, 2011 Compared with Three Months Ended September 30, 2010

We reported net income attributable to Southwestern Energy of $175.2 million for the three months ended September 30, 2011, or $0.50 per diluted share, compared to net income attributable to Southwestern Energy of $160.7 million, or $0.46 per diluted share, for the comparable period in 2010.

Our natural gas and oil production increased to 128.9 Bcfe for the three months ended September 30, 2011, up 23.9 Bcfe or 23%, from the three months ended September 30, 2010. The increase in our third quarter 2011 production was primarily due to a 19.6 Bcf increase in net production from our Fayetteville Shale play and a 7.2 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 2.9 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The average price realized for our natural gas production, including the effects of hedges, decreased approximately 8% to $4.30 per Mcf for the three months ended September 30, 2011 compared to the same period in 2010.

Operating income from our E&P segment was $228.5 million for the three months ended September 30, 2011 compared to operating income of $216.7 million for the same period in 2010. The increase in operating income was the result of the revenue impact of our 23% growth in production which was partially offset by the 8% decline in our average realized natural gas prices and a $51.9 million increase in operating costs and expenses that resulted from our significant production growth.

Operating income for our Midstream Services segment was $66.8 million for the three months ended September 30, 2011, up from $53.4 million for the three months ended September 30, 2010, due to an increase of $19.6 million in gathering revenues, which were partially offset by a $6.1 million increase in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our significant growth in volumes gathered. Volumes gathered grew to 190.9 Bcf for the three months ended September 30, 2011 compared to 155.7 Bcf for the same period in 2010.

Capital investments were $470.4 million for the three months ended September 30, 2011, of which $421.2 million was invested in our E&P segment, compared to total capital investments of $516.6 million for the same period of 2010, of which $420.3 million was invested in our E&P segment.

Nine Months Ended September 30, 2011 Compared with Nine Months Ended September 30, 2010

We reported net income attributable to Southwestern Energy of $479.2 million for the nine months ended September 30, 2011, or $1.37 per diluted share, up $24.6 million from $454.6 million, or $1.30 per diluted share, for the comparable period in 2010.

Our natural gas and oil production increased to 366.7 Bcfe for the nine months ended September 30, 2011, up 25% from the nine months ended September 30, 2010. The increase in 2011 production was primarily due to a 68.9 Bcf increase in net production from our Fayetteville Shale play and a 15.1 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 10.5 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. The average price realized for our natural gas production, including the effects of hedges, decreased approximately 11% to $4.24 per Mcf for the nine months ended September 30, 2011 compared to the same period in 2010.

Our E&P segment reported operating income of $629.3 million for the nine months ended September 30, 2011, down from $629.6 million for the nine months ended September 30, 2010. The decrease in operating income was due to a $351.6 million increase in revenues due to higher natural gas production volumes, which was more than offset by a $191.1 million decrease in revenues due to lower realized natural gas prices and a $156.1 increase in our operating costs and expenses associated with the natural gas production increase.

Operating income for our Midstream Services segment was $180.4 million for the nine months ended September 30, 2011, up from $134.8 million for the nine months ended September 30, 2010, due to an increase of $70.4 million in gathering revenues and an increase of $4.3 million in the margin generated from our natural gas marketing activities partially offset by a $29.1 million increase in operating costs and expenses, exclusive of natural gas purchase costs, that resulted from our significant growth in volumes gathered. Volumes gathered grew to 545.7 Bcf for the nine months ended September 30, 2011 compared to 421.6 Bcf for the same period in 2010.

Net cash provided by operating activities increased 7% to $1,300.2 million for the nine months ended September 30, 2011 compared to $1,215.1 million for the same period in 2010 due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher natural gas production and gathering volumes, partially offset by lower realized natural gas prices, higher operating expenses resulting from our growth and a decrease in changes in working capital. We had capital investments of $1,556.9 million for the nine months ended September 30, 2011, of which $1,365.4 million was invested in our E&P segment, compared to total capital investments of $1,533.8 million for the same period of 2010, of which $1,273.0 million was invested in our E&P segment.

Recent Development

Production Guidance Update

As a result of strong performance from our Fayetteville Shale and Marcellus Shale operating areas, we revised our expected gas and oil production range for 2011 to 496 to 500 Bcfe, up from our previous production guidance of 483 to 491 Bcfe. The revised total gas and oil production guidance for 2011 is an increase of approximately 23% over our 2010 gas and oil production (using midpoints). Of the total expected production in 2011, approximately 430 to 434 Bcf is expected to come from the Fayetteville Shale.

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, income tax expense and stock-based compensation are discussed on a consolidated basis.

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
Revenues (in thousands)	$ 555,620	$ 491,900	$ 1,561,658	$ 1,405,824
Operating costs and expenses (in thousands)	$ 327,144	$ 275,204	$ 932,360	$ 776,224
Operating income (loss) (in thousands)	$ 228,476	$ 216,696	$ 629,298	$ 629,600
Gas production (Bcf)	128.7	104.7	366.2	292.4
Oil production (MBbls)	24	44	79	137
Total production (Bcfe)	128.9	105.0	366.7	293.3
Average gas price per Mcf, including hedges	$ 4.30	$ 4.67	$ 4.24	$ 4.76
Average gas price per Mcf, excluding hedges	$ 3.71	$ 3.91	$ 3.75	$ 4.12
Average oil price per Bbl	$ 88.35	$ 74.37	$ 93.54	$ 75.39
Average unit costs per Mcfe:				
Lease operating expenses	$ 0.86	$ 0.85	$ 0.84	$ 0.83
General & administrative expenses	$ 0.25	$ 0.28	$ 0.26	$ 0.29
Taxes, other than income taxes	$ 0.11	$ 0.12	$ 0.11	$ 0.12
Full cost pool amortization	$ 1.28	$ 1.31	$ 1.29	$ 1.35

Revenues

Revenues for our E&P segment were up $63.7 million, or 13%, for the three months ended September 30, 2011 compared to the same period in 2010. Higher natural gas production volumes in the third quarter of 2011 increased revenues by $111.9 million while lower realized prices for our natural gas production decreased revenue by $47.1 million compared to the third quarter of 2010. E&P revenues were up $155.8 million, or 11% for the nine months ended September 30, 2011. Higher natural gas production volumes in the first nine months of 2011 increased revenues by $351.6 million while lower realized prices for our natural gas production decreased revenue by $191.1 million. We expect our natural gas production volumes to continue to increase due to the development of our Fayetteville Shale properties in Arkansas and our Marcellus Shale properties in Pennsylvania. Natural gas and oil prices are difficult to predict and subject to wide price fluctuations. As of October 25, 2011, we had hedged 80.0 Bcf of our remaining 2011 natural gas production and gas in underground storage and 265.7 Bcf of our 2012 natural gas production and gas in underground storage and 185.2 Bcf of our 2013 natural gas production to help limit our exposure to price fluctuations. We refer you to Note 7 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

For the three months ended September 30, 2011, our natural gas and oil production increased 23% to 128.9 Bcfe, up from 105.0 Bcfe from the same period in 2010, and was produced entirely by our properties in the United States. The 23.9 Bcfe increase in our 2011 production was primarily due to a 19.6 Bcf increase in net production from our Fayetteville Shale play and a 7.2 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 2.9 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Natural gas production represented nearly 100% of our total production for the three months ended September 30, 2011 and was up approximately 23% to 128.7 Bcf compared to the same period in 2010. Net production from the Fayetteville Shale and Marcellus Shale properties was 111.9 Bcf and 7.4 Bcf, respectively, for the three months ended September 30, 2011 compared to 92.3 Bcf and 0.2 Bcf for the same period in 2010. Natural gas and oil production for the nine months ended September 30, 2011 was up approximately 25% to 366.7 Bcfe, up from 293.3 Bcfe from the same period in 2010, and was produced entirely by our properties in the United States. The 73.4 Bcfe increase in our 2011 production was primarily due to a 68.9 Bcf increase in net production from our Fayetteville Shale play and a 15.1 Bcf increase in net production from our Marcellus Shale properties, which more than offset a combined 10.6 Bcfe decrease in net production from our East Texas and Arkoma Basin properties. Natural gas production represented nearly 100% of our total production for the nine months ended September 30, 2011 and was up approximately 25% to 366.2 Bcf compared to the same period in 2010. Net production from our Fayetteville Shale and Marcellus Shale properties was 320.4 Bcf and 15.2 Bcf, respectively, for the nine months ended September 30, 2011 compared to 251.4 Bcf and 0.1 Bcf, respectively, for the same period in 2010.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, decreased $0.37 per Mcf to $4.30 per Mcf for the three months ended September 30, 2011, as compared to the same period in 2010. The decrease was the result of a $0.20 Mcf decrease in average natural gas prices, excluding hedges, in addition to a $0.17 Mcf decreased effect of our price hedging activities. The average price realized for our natural gas production, including the effects of hedges, decreased 11% to $4.24 per Mcf for the nine months ended September 30, 2011, as compared to the same period in 2010. The decrease in the average price realized for the nine months ended September 30, 2011, as compared to the same period in 2010, reflects the decrease in average natural gas prices, excluding hedges, in addition to the decreased effect of our price hedging activities. We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational basis differentials (we refer you to Item 3 and Note 7 to the unaudited condensed consolidated financial statements included in this Form 10-Q for additional discussion).

Disregarding the impact of hedges, the average price received for our natural gas production for the three months ended September 30, 2011 of $3.71 per Mcf was approximately $0.20 per Mcf lower than the three months ended September 30, 2010. Our hedging activities increased the average natural gas price $0.59 per Mcf for the three months ended September 30, 2011 compared to an increase of $0.76 per Mcf for the same period in 2010. Disregarding the impact of hedges, the average price received for our natural gas production for the nine months ended September 30, 2011 of $3.75 per Mcf was approximately $0.37 per Mcf lower than the nine months ended September 30, 2010. Our hedging activities increased the average natural gas price $0.49 per Mcf for the nine months ended September 30, 2011 compared to an increase of $0.64 per Mcf for the same period in 2010.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to locational basis differentials, while transportation charges and fuel charges also reduce the price received. Excluding the impact of hedges, the average price received for our natural gas production for the nine months ended September 30, 2011 of $3.75 per Mcf was approximately $0.46 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We had protected approximately 55% of our natural gas production for the nine months ended September 30, 2011 from the impact of widening basis differentials through our hedging activities and sales arrangements. For the remainder of 2011, we expect our total natural gas sales discount to NYMEX to be $0.45 to $0.50 per Mcf. At September 30, 2011, we had basis protected on approximately 55 Bcf of our remaining 2011 expected natural gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX natural gas prices of approximately $0.01 per Mcf, excluding transportation and fuel charges. Additionally, at September 30, 2011, we had basis protected on approximately 105 Bcf of our 2012 expected natural gas production and 45 Bcf of our 2013 expected natural gas production through financial hedging activities and physical sales arrangements.

In addition to the basis hedges discussed above, at September 30, 2011, we had NYMEX fixed price hedges in place on notional volumes of 64.4 Bcf of our remaining 2011 natural gas production at an average price of $5.24 per MMBtu and collars in place on notional volumes of 15.6 Bcf of our remaining 2011 natural gas production at an average floor and ceiling price of $5.09 and $6.50 per MMBtu, respectively.

As of September 30, 2011, we had NYMEX fixed price hedges in place on notional volumes of 185.2 Bcf and 185.2 Bcf of our 2012 and 2013 natural gas production, respectively, and we had collars in place on notional volumes of 80.5 Bcf of our 2012 natural gas production.

Operating Income

Operating income from our E&P segment was $228.5 million for the three months ended September 30, 2011 compared to operating income of $216.7 million for the same period in 2010. The increase in operating income was the result of the revenue impact of our 23% growth in production which was partially offset by the 8% decline in our average realized natural gas prices and a $51.9 million increase in operating costs and expenses that resulted from our significant production growth. Operating income from our E&P segment decreased to $629.3 million for the nine months ended September 30, 2011 compared to $629.6 million for the same period in 2010. The decrease in operating income was due to a $191.1 million decrease in revenues due to lower realized natural gas prices and a $156.1 million increase in our operating costs and expenses associated with the natural gas production increase, offset by a $351.6 million increase in revenues due to higher natural gas production volumes.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment were $0.86 for three months ended September 30, 2011 compared to $0.85 for the same period in 2010. Lease operating expenses per Mcfe for our E&P segment were $0.84 for the nine months ended September 30, 2011 compared to $0.83 for the same period in 2010. The increases in lease operating expenses per unit of production for the three- and nine-month periods ended September 30, 2011, as compared to the same periods of 2010, are primarily due to increased gathering and salt water disposal costs.

General and administrative expenses per Mcfe were $0.25 and $0.28 for the three months ended September 30, 2011 and 2010, respectively, and decreased 10% to $0.26 for the nine months ended September 30, 2011, reflecting the effects of our increased production volumes. In total, general and administrative expenses for our E&P segment were $32.6 million for the three months ended September 30, 2011 compared to $29.6 million for the same period in 2010, and were $96.7 million for the nine months ended September 30, 2011 compared to $86.3 million for the same period in 2010. Payroll, employee incentive compensation and other employee-related costs associated with our E&P operations decreased by $1.5 million for the three months ended September 30, 2011 and increased by $1.7 million for the nine months ended September 30, 2011 compared to the same periods in 2010 primarily as a result of the expansion of our E&P operations.

Taxes other than income taxes per Mcfe decreased to $0.11 for both the three and nine months ended September 30, 2011 compared to $0.12 for the same periods in 2010. 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 $1.28 per Mcfe for the three months ended September 30, 2011 compared to $1.31 per Mcfe for the same period in 2010. The decline in the average amortization rate for the three months ended September 30, 2011 compared to the same period of 2010 was primarily the result of lower acquisition and development costs, combined with the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2011, as the proceeds from the sale were appropriately credited to the full cost pool. For the first nine months of 2011, our full cost pool amortization rate averaged $1.29 per Mcfe compared to $1.35 per Mcfe for the same period in 2010. The decline in the average amortization rate for the nine months ended September 30, 2011 compared to the same period of 2010 was primarily due to the sale of certain East Texas oil and natural gas leases and wells in the second quarter of 2010, as the proceeds from the sale were appropriately credited to the full cost pool, combined with lower acquisition and development costs. The amortization rate is impacted by the timing and the amount of reserve additions and costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserves.

Unevaluated costs excluded from amortization were $870.2 million at September 30, 2011 compared to $712.1 million at December 31, 2010. The increase in unevaluated costs since December 31, 2010 resulted from a $80.6 million increase in our undeveloped leasehold acreage and seismic costs, a $40.8 million increase in our drilling activity, and a $22.3 million increase in capitalized interest. Unevaluated costs excluded from amortization at September 30, 2011 included $25.1 million related to our properties in Canada, compared to $10.7 million at December 31, 2010.

The timing and amount of production and reserve changes could have a material impact on our per unit costs.

Midstream Services

	For the three months ended September 30,		For the nine months ended September 30,	
	2011	2010	2011	2010
	($ in thousands, except volumes)			
Revenues – marketing	$ 639,175	$ 561,813	$ 1,887,383	$ 1,611,492
Revenues – gathering	$ 104,656	$ 85,096	$ 296,325	$ 225,918
Gas purchases – marketing	$ 629,899	$ 552,539	$ 1,862,736	$ 1,591,138
Operating costs and expenses	$ 47,095	$ 40,980	$ 140,574	$ 111,491
Operating income	$ 66,837	$ 53,390	$ 180,398	$ 134,781
Gas volumes marketed (Bcf)	153.3	130.2	450.4	357.0
Gas volumes gathered (Bcf)	190.9	155.7	545.7	421.6

Revenues

Revenues from our marketing activities were up 14% to $639.2 million for the three months ended September 30, 2011 and were up 17% to $1,887.4 million for the nine months ended September 30, 2011 compared to the respective periods of 2010. The increases in marketing revenues resulted from increases in the volumes marketed, partially offset by decreases in the prices received for volumes marketed. For the three months ended September 30, 2011, volumes marketed increased 18% and the price received for volumes marketed decreased 3% compared to the same period in 2010. For the nine months ended September 30, 2011, volumes marketed increased 26% and the price received for volumes marketed decreased 7% compared to the same period in 2010. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in natural gas purchase expenses. Of the total volumes marketed, production from our affiliated E&P operated wells accounted for 96% and 94% of the marketed volumes for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, production from our E&P operated wells accounted for 94% and 96% of the marketed volumes, respectively.

Revenues from our gathering activities were up 23% to $104.7 million for the three months ended September 30, 2011 and up 31% to $296.3 million for the nine months ended September 30, 2011 compared to the respective periods in 2010. The increases in gathering revenues resulted from a 23% increase in natural gas volumes gathered for the three months ended September 30, 2011 and a 29% increase in natural gas volumes gathered for the nine months ended September 30, 2011 compared to the respective periods in 2010. Substantially all of the increases in gathering revenues for the three months ended September 30, 2011 and nine months ended September 30, 2011 resulted from increases in volumes gathered related to the Fayetteville Shale play. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to our Fayetteville Shale and Marcellus Shale properties are developed and production increases as expected.

Operating Income

Operating income from our Midstream Services segment increased to $66.8 million for the three months ended September 30, 2011 compared to $53.4 million for the same period in 2010 and increased to $180.4 million for the nine months ended September 30, 2011 compared to $134.8 million for the same period in 2010. The increases in operating income reflect the substantial increases in natural gas volumes gathered which primarily resulted from our increased E&P production volumes. The $13.4 million increase in operating income for the three months ended September 30, 2011 was primarily due to a $19.6 million increase in gathering revenues which was partially offset by an increase in operating costs and expenses of $6.1 million that resulted from our significant growth in volumes gathered. The $45.6 million increase in operating income for nine months ended September 30, 2011 was primarily due to an $70.4 million increase in gathering revenues which was partially offset by an increase in operating costs and expenses of $29.1 million that resulted from our significant growth in volumes gathered. The remaining changes in operating income were due to changes in the margin generated by our natural gas marketing activities. Marketing margin increased $4.3 million for the nine months ended September 30, 2011 compared to the respective periods of 2010. Margins are primarily driven by volumes of natural gas marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. We enter into hedging activities from time to time with respect to our natural 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

Interest expense, net of capitalization, decreased to $5.7 million for the three months ended September 30, 2011 compared to $6.6 million for the same period in 2010. The decrease in interest expense, net of capitalization, for the three-month period ended September 30, 2011 was due to an increase in capitalized interest for the three-month period ended September 30, 2011 compared to the same period in 2010. Interest expense, net of capitalization, was $19.3 million for both the nine months ended September 30, 2011 and September 30, 2010. We capitalized interest of $11.9 million and $32.5 million for the three- and nine-month periods ended September 30, 2011, respectively, compared to $8.5 million and $24.9 million for the same periods in 2010.

Income Taxes

Our effective tax rates were 39.5% and 39.0% for the nine months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011, we recorded an income tax expense of $312.7 million compared to an income tax expense of $291.1 million for the same period in 2010. In conjunction with our filing of state income tax returns, the Company annually assesses its combined state tax rate due to the growth of our business and presence in higher state tax jurisdictions. Any increase in deferred income taxes as a result of this assessment could have a significant effect on our fourth quarter effective tax rate.

Stock-Based Compensation Expense

We recognized expense of $1.9 million and capitalized $2.2 million for stock-based compensation during the three-month period ended September 30, 2011 compared to $2.2 million expensed and $1.7 million capitalized for the comparable period in 2010. We recognized expense of $6.6 million and capitalized $6.0 million for stock-based compensation during the nine-month period ended September 30, 2011 compared to $6.6 million expensed and $5.1 million capitalized for the comparable period in 2010. We refer you to Note 14 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, 2011, 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 entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our results of operations, financial position or cash flows.

On May 12, 2011, the FASB issued guidance on fair value measurement and disclosure requirements outlined in Accounting Standards Update No. 2011-04, *Fair Value Measurement (Topic 820)–Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS* ("Update 2011-04"). Update 2011-04 expands existing fair value disclosure requirements, particularly for Level 3 inputs, including: quantitative disclosure of the unobservable inputs and assumptions used in the measurement; description of the valuation processes in place and sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs; the level of items (in the fair value hierarchy) that are not measured at fair value in the balance sheet but whose fair value must be disclosed; and the use of a nonfinancial asset if it differs from the highest and best use assumed in the fair value measurement. The amendments in Update 2011-04 must be applied prospectively and are effective during interim and annual periods beginning after December 15, 2011. The implementation of the disclosure requirement is not expected to have a material impact on the Company's consolidated financial statements.

On June 16, 2011, the FASB issued Accounting Standards Update No. 2011-05, *Presentation of Comprehensive Income* ("Update 2011-05"), which amends Topic 200, *Comprehensive Income*. Update 2011-05 eliminates the option to present components of 'other comprehensive income' ("OCI") in the statement of changes in stockholders' equity, and requires presentation of total comprehensive income and components of net income in a single statement of comprehensive income, or in two separate, consecutive statements. Update 2011-05 requires presentation of reclassification adjustments for items transferred from OCI to net income on the face of the financial statements where the components of net income and the components of OCI are presented. The amendments do not change current treatment of items in OCI, transfer of items from OCI, or reporting items in OCI net of the related tax impact. Update 2011-05 is effective for fiscal years and interim periods beginning after December 15, 2011. The implementation of these changes is not expected to have an impact on the Company's results of operations, financial position or cash flows.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our Credit Facility and funds accessed through debt and equity markets as our primary sources of liquidity.

For the remainder of 2011, assuming natural gas prices remain at current levels, we expect to draw on a portion of the funds available under our Credit Facility to fund our planned capital investments (discussed below under "Capital Investments"), which are expected to exceed the net cash generated by our operations. We refer you to Note 9 to the consolidated financial statements included in this Form 10-Q and the section below under "Financing Requirements" for additional discussion of our Credit Facility.

Net cash provided by operating activities increased 7% to $1,300.2 million for the nine months ended September 30, 2011 compared to $1,215.1 million for the same period in 2010, due to an increase in net income adjusted for non-cash expenses primarily resulting from increased revenues due to higher natural gas production and gathering volumes, partially offset by lower realized natural gas prices, higher operating expenses resulting from our growth and a decrease in changes in working capital. During the nine months ended September 30, 2011, requirements for our capital investments were funded primarily from our cash generated by operating activities and borrowings under our Credit Facility. For the nine months ended September 30, 2011, cash generated from our operating activities funded 84% of our cash requirements for capital investments and 81% for the nine months ended September 30, 2010.

At September 30, 2011 our capital structure consisted of 26% debt and 74% equity. We believe that our operating cash flow, restricted cash and available funds under our Credit Facility will be adequate to meet our capital and operating requirements for 2011. 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 natural gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors which are impacted by the overall state of the economy. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Item 3, "Quantitative and Qualitative Disclosures about Market Risks" and Note 7 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 $1.6 billion for the nine months ended September 30, 2011 compared to $1.5 billion for the same period in 2010. Our E&P segment investments were $1.4 billion for the nine months ended September 30, 2011 compared to $1.3 billion for the same period in 2010. Our E&P segment capitalized internal costs of $109.6 million for the nine months ended September 30, 2011 compared to $100.1 million for the comparable period in 2010. 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.

Financing Requirements

Our total debt outstanding was $1.3 billion at September 30, 2011 compared to $1.1 billion at December 31, 2010.

In February 2011, we amended and restated our unsecured revolving credit facility, increasing the borrowing capacity to $1.5 billion and extending the maturity date to February 2016. The amount available under the revolving credit facility may be increased to $2.0 billion at any time upon the Company's agreement with its existing or additional lenders. We had $599.8 million outstanding under our revolving credit facility at September 30, 2011 compared to $421.2 million at December 31, 2010.

The interest rate on our Credit Facility is calculated based upon our public debt rating and is currently 200 basis points over LIBOR. Our publicly traded notes are rated BBB- by Standard and Poor's and we have a Corporate Family Rating of Ba1 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, 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 hedging activities, pension and other postretirement liabilities as well as the effects of non-cash entries that result from any full cost ceiling impairments occurring after the date of the agreement. At September 30, 2011, our capital structure under our Credit Facility was 27% debt and 73% equity, which excluded hedging activities, pension and other postretirement liabilities but included the effect of the full cost ceiling impairment that occurred in 2009. We were in compliance with all of the covenants of our Credit Facility at September 30, 2011. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our Credit Facility, we may have to decrease our capital investment plans.

Our capital structure consisted of 26% debt and 74% equity at September 30, 2011 and 27% debt and 73% equity at December 31, 2010. Equity at September 30, 2011 included an accumulated other comprehensive gain of $242.5 million related to our hedging activities and a loss for $11.9 million related to our pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on current market values for our hedges at September 30, 2011 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 October 25, 2011 we had NYMEX commodity price hedges in place on 80.0 Bcf of our remaining targeted 2011 natural gas production and gas in underground storage, 265.7 Bcf of our expected 2012 natural gas production and gas in underground storage and 185.2 Bcf of our expected 2013 natural gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans.

Contractual Obligations and Contingent Liabilities and Commitments

During the first and second quarters of 2011, the Company's marketing subsidiary, Southwestern Energy Services Company ("SES"), entered into a number of short and long term firm transportation service and gathering agreements in support of the Company's growing Marcellus Shale operations in Pennsylvania and the Company has provided certain guarantees of a portion of SES's obligations under these agreements. In March 2011, SES entered into a precedent agreement with Millennium Pipeline Company, L.L.C. pursuant to which it will enter into short and long term firm natural gas transportation services on Millennium's existing system and expansions of the system expected to be in-service by late 2012 and late 2013. Certain of SES's obligations under the precedent agreement are subject to the satisfaction of conditions precedent. On June 30, 2011, SES entered into a long term agreement with Bluestone Gathering, a wholly owned subsidiary of DTE Energy Company, pursuant to which Bluestone Gathering will build and operate a natural gas gathering system in Susquehanna County, Pennsylvania and Broome County, New York, and provide gathering services to SES in support of a portion of the Company's future Marcellus Shale natural gas production. The projected in-service date for the gathering system is as early as the second quarter of 2012. SES also executed firm transportation agreements with Tennessee Gas Pipeline that increase the Company's ability to move its Marcellus Shale natural gas production in the short term to market as well as a precedent agreement for an expansion project with a projected in-service date of November 2013 pursuant to which SES has subscribed for 100,000 Dekatherm/day of capacity. As of September 30, 2011, SES's obligations for demand and similar charges under the firm transportation agreements totaled approximately $120.4 million and the Company currently has no guarantee obligations with respect to the firm transportation agreements and the gathering project and services.

On October 6, 2011, the Company's subsidiary, Southwestern Energy Production Company ("SEPCO"), entered into a 15-year agreement with a subsidiary of Boardwalk Pipeline Partners for the construction of a gathering system in Susquehanna and Lackawanna counties in Pennsylvania, which once constructed is expected to have a delivery capacity of 275,000 Dekatherm/day.

We have various contractual obligations in the normal course of our operations and financing activities. Other than the increase in our firm transportation and gathering commitments, there have been no material changes to our contractual obligations from those disclosed in our 2010 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 CAD $47 million in the aggregate over a three year period. 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 CAD $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 commenced our Canada exploration program in 2010 and, as of September 30, 2011, 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 $12.5 million to our pension plans and $0.1 million to our postretirement benefit plan in 2011. As of September 30, 2011, we have contributed $9.8 million to our pension plans and $0.1 million to our postretirement benefit plan during the year. At September 30, 2011, we recognized a liability of $13.8 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $15.9 million at December 31, 2010.

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 likely have a material adverse impact on our results of operations, financial position or cash flows, 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. For further information regarding commitments and contingencies, we refer you to Note 10 in the unaudited condensed consolidated financial statements included in this Form 10-Q.

Working Capital

We had positive working capital of $69.9 million at September 30, 2011 compared to negative working capital of $113.1 million at December 31, 2010. Current assets increased by $255.2 million at September 30, 2011 compared to December 31, 2010, primarily due to a $185.1 million increase in our hedging asset. The increase in current assets also includes a $69.3 million increase in restricted cash related to the sale of certain oil and natural gas leases, wells and gathering equipment in East Texas. The sale occurred in the second quarter of 2011, and we deposited the proceeds of the sale with a qualified intermediary to facilitate potential like-kind exchange transactions pursuant to Section 1031 of the Internal Revenue Code. Current liabilities increased by $72.3 million at September 30, 2011 compared to December 31, 2010 primarily as a result of a $71.8 million increase in our current deferred income taxes related to our hedging activities. We maintain access to funds that may be needed to meet capital requirements through our Credit Facility described in "Financing Requirements" above.

Gas in Underground Storage

We record our natural gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. The natural 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 natural gas, we utilize the natural gas futures market in assessing the price we expect to be able to realize for our natural gas in inventory. A significant decline in the future market price of natural gas could result in write-downs of our natural 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. See "Commodities Risk" below for discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At September 30, 2011, we had $1.3 billion of total debt with a weighted average interest rate of 4.99%. Our revolving credit facility has a floating interest rate (2.205% at September 30, 2011). At September 30, 2011, we had $599.8 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 commercial banks, investment banks and integrated energy companies 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 recent volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At September 30, 2011, the fair value of our financial instruments related to natural gas production and gas in underground storage was a $392.1 million asset.

	Volume (Bcf)	Weighted Average Price to be Swapped ($/MMBtu)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at September 30, 2011 ($ in millions)
Natural Gas:						
Fixed Price Swaps:						
2011 [1]	64.7	$ 5.24	$ —	$ —	$ —	$ 91.5
2012 [2]	185.9	$ 5.02	$ —	$ —	$ —	$ 140.1
2013	185.2	$ 5.06	$ —	$ —	$ —	$ 46.1
Floating Price Swaps:						
2011	0.6	$ 4.86	$ —	$ —	$ —	$ (0.7)
2012	4.6	$ 5.67	$ —	$ —	$ —	$ (6.7)
Costless-Collars:						
2011	15.6	$ —	$ 5.09	$ 6.50	$ —	$ 19.9
2012	80.5	$ —	$ 5.50	$ 6.67	$ —	$ 104.0
Basis Swaps:						
2011	9.2	$ —	$ —	$ —	$ 0.13	$ (0.7)
2012	37.7	$ —	$ —	$ —	$ 0.10	$ (1.2)
2013	30.1	$ —	$ —	$ —	$ 0.07	$ (0.4)
2014	9.1	$ —	$ —	$ —	$ (0.03)	$ 0.2

(1) Includes fixed-price swaps for 0.3 Bcf relating to future sales from our underground storage facility that have a fair value asset of approximately $0.3 million.
(2) Includes fixed-price swaps for 0.7 Bcf relating to future sales from our underground storage facility that have a fair value liability of approximately $0.5 million.

At September 30, 2011, 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 natural gas and oil sales. For the nine months ended September 30, 2011, we recorded an unrealized loss of $0.2 million related to the basis swaps that did not qualify for hedge accounting treatment and an unrealized loss of $0.5 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, 2010, we had outstanding natural gas price swaps on total notional volumes of 66.8 Bcf in 2011, 68.1 Bcf in 2012 and 36.5 Bcf in 2013 for which we will receive fixed prices ranging from $5.00 to $7.03 per MMBtu. At December 31, 2010, we had collars in place on notional volumes of 62.1 Bcf in 2011 at an average floor and ceiling price of $5.09 and $6.50 per MMBtu, respectively, and collars on notional volumes of 80.5 Bcf in 2012 at an average floor and ceiling price of $5.50 and $6.67 per MMBtu, respectively.

Additionally, at December 31, 2010, we had outstanding fixed price basis differential swaps on 12.0 Bcf of 2011 natural gas production that did not qualify for hedge treatment.

Midstream Services

At September 30, 2011, our Midstream Services segment had outstanding fair value hedges in place on 0.1 Bcf and 0.1 Bcf of natural gas for 2011 and 2012, respectively. These hedges are a mixture of floating-price swap purchases and sales relating to our natural gas marketing activities. These hedges have contract months from October 2011 and March 2012 and have a net fair value liability of $0.4 million as of September 30, 2011.

ITEM 4. CONTROLS AND PROCEDURES.

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC’s rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2011. There were no changes in our internal control over financial reporting during the three months ended September 30, 2011 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 laws and regulations relating to the protection of the environment. Our 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 our financial position, results of operations, and cash flows.

In February 2009, SEPCO was added as a defendant in a Third Amended Petition in the matter of Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al. In the Sixth Amended Petition, filed in July 2010, in the 273 rd District Court in Shelby County, Texas (collectively, the "Sixth Petition") plaintiff alleged that, in 2005, they provided SEPCO with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that SEPCO refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, the plaintiff's allegations in the Sixth Petition included various statutory and common law claims, including, but not limited to claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by SEPCO between February 15, 2005 and February 15, 2006. In the Sixth Petition, plaintiff sought actual damages of over $55 million as well as other remedies, including special damages and punitive damages of four times the amount of actual damages established at trial.

Immediately before the commencement of the trial in November 2010, plaintiff was permitted, over SEPCO's objections, to file a Seventh Amended Petition claiming actual damages of $46 million and also seeking the equitable remedy of disgorgement of all profits for the misappropriation of trade secrets and the breach of fiduciary duty claims. In December 2010, the jury found in favor of the plaintiff with respect to all of the statutory and common law claims and awarded $11.4 million in compensatory damages. The jury did not, however, award the plaintiff any special, punitive or other damages. In addition, the jury separately determined that SEPCO's profits for purposes of disgorgement were $381.5 million. This profit determination does not constitute a judgment or an award. The plaintiff's entitlement to disgorgement of profits as an equitable remedy will be determined by the judge and it is within the judge's discretion to award none, some or all the amount of profit to the plaintiff. On December 31, 2010, the plaintiff filed a motion to enter the judgment based on the jury's verdict. On February 11, 2011, SEPCO filed a motion for a judgment notwithstanding the verdict and a motion to disregard certain findings. On March 11, 2011, the plaintiff filed an amended motion for judgment and intervenor filed its motion for judgment seeking not only the monetary damages and the profits determined by the jury but also seeking, as a new remedy, a constructive trust for profits from 143 wells as well as future drilling and sales of properties in the prospect areas. A hearing on the post-verdict motions was held on March 14, 2011. At the suggestion of the judge, all parties voluntarily agreed to participate in non-binding mediation efforts. The mediation occurred on April 6, 2011 and was unsuccessful. On June 6, 2011, SEPCO received by mail a letter dated June 2, 2011 from the judge, in which he made certain rulings with respect to the post-verdict motions and responses filed by the parties. In his rulings, the judge denied SEPCO's motion for judgment, judgment notwithstanding the verdict and to disregard certain findings. Plaintiff's and intervenor's claim for a constructive trust was denied but the judge ruled that plaintiff and intervenor shall recover from SEPCO $11.4 million and a reasonable attorney's fee of 40% of the total damages awarded and are entitled to recover on their claim for disgorgement. The judge instructed that SEPCO calculate the profit on the designated wells for each respective period. SEPCO performed the calculation and provided it to the judge in June 2011. On July 5, 2011, plaintiff and intervenor filed a letter with the court raising objections to the accounting provided by SEPCO, to which SEPCO filed a response on July 11, 2011. On July 12, 2011, the judge sent a letter to the parties in which he ruled that after reviewing the parties' respective position letters, he was awarding $23.9 million in disgorgement damages in favor of the plaintiff and intervenor. In the July 12, 2011 letter, the judge instructed the plaintiff and intervenor to prepare a judgment for his approval prior to July 21, 2011 consistent with his findings in his June 2, 2011 letter and the disgorgement award. On August 24, 2011, a judgment was entered pursuant to which plaintiff and intervenor are entitled to recover approximately $11.4 million in actual damages and approximately $23.9 million in disgorgement as well as prejudgment interest and attorneys' fees which currently are estimated to be up to $8.9 million and all costs of court of the plaintiff and intervenor. On September 22, 2011, the plaintiff and intervenor filed a motion to modify, correct or reform the judgment which requested that the court vacate the final judgment ordering SEPCO to produce additional accounting information and reconsider the amount SEPCO should disgorge. On September 23, 2011, SEPCO filed a motion for a new trial.

The Company believes that SEPCO has a number of legal grounds for appealing the judgment, all of which will be vigorously pursued. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate defenses, and after considering the advice of counsel, the Company has determined that, although reasonably possible after exhaustion of all appeals, an adverse final outcome to this lawsuit is not probable. As such, the Company has not accrued any amounts with respect to this lawsuit. If the plaintiff and intervenor were to ultimately prevail in the appellate process, the Company currently estimates, based on the judgments to date, that SEPCO's potential liability would be up to $44.2 million, including interest and attorney's fees. The Company's assessment may change in the future due to occurrence of certain events, such as denied appeals, and such re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

In March 2010, the Company's subsidiary, SEECO, Inc., was served with a subpoena from a federal grand jury in Little Rock, Arkansas. Based on the documents requested under the subpoena and subsequent discussions described below, the Company believes the grand jury is investigating matters involving approximately 27 horizontal wells operated by SEECO in Arkansas, including whether appropriate leases or permits were obtained therefor and whether royalties and other production attributable to federal lands have been properly accounted for and paid. The Company believes it has fully complied with all requests related to the federal subpoena and delivered its affidavit to that effect. The Company and representatives of the Bureau of Land Management and the U.S. Attorney have had discussions since the production of the documents pursuant to the subpoena. In January 2011, the Company voluntarily produced additional materials informally requested by the government arising from these discussions. Although, to the Company's knowledge, no proceeding in this matter has been initiated against SEECO, the Company cannot predict whether or when one might be initiated. The Company intends to fully comply with any further requests and to cooperate with any related investigation. No assurance can be made as to the time or resources that will need to be devoted to this inquiry or the impact of the final outcome of the discussions or any related proceeding.

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

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 2010 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: October 27, 2011

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