SWIFT ENERGY CO
Form 10-Q
August 03, 2009

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

Form 10-Q

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

For the quarterly period ended June 30, 2009
Commission File Number 1-8754

SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

Texas	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

16825 Northchase Drive, Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Exchanges on Which Registered:
Common Stock, par value $.01 per share	New York Stock Exchange

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, and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act.
Large þ Accelerated o Non-accelerated o Smaller o

accelerated filer	filer	filer	reporting company

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

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

Common Stock ($.01 Par Value)	31,219,546 Shares
(Class of Stock)	(Outstanding at July 31, 2009)

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SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2009
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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	June 30, 2009 (Unaudited)	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$231	$283
Accounts receivable-		
Oil and gas sales	38,233	37,364
Joint interest owners	840	4,235
Other Receivables	8,647	20,065
Other current assets	24,171	15,575
Current assets held for sale	564	564
Total Current Assets	72,686	78,086
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	3,337,896	3,270,159
Unproved properties	87,017	91,252
	3,424,913	3,361,411
Furniture, fixtures, and other equipment	37,901	37,669
	3,462,814	3,399,080
Less – Accumulated depreciation, depletion, and amortization	(2,132,063)	(1,967,633)
	1,330,751	1,431,447
Other Assets:		
Debt issuance costs	5,508	6,107
Restricted assets	1,413	1,648
	6,921	7,755
	$1,410,358	$1,517,288
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$53,477	$66,802
Accrued capital costs	15,898	74,315
Accrued interest	7,182	7,207
Undistributed oil and gas revenues	5,087	5,175
Total Current Liabilities	81,644	153,499
Long-Term Debt	628,000	580,700
Deferred Income Taxes	106,925	130,899
Asset Retirement Obligation	46,668	48,785
Other Long-Term Liabilities	2,409	2,528
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	---	---

Common stock, $.01 par value, 85,000,000 shares authorized, 31,607,453 and 31,336,472 shares issued, and 31,189,499 and 30,868,588 shares outstanding, respectively	316	313
Additional paid-in capital	439,322	435,307
Treasury stock held, at cost, 417,954 and 467,884 shares, respectively	(8,994)	(10,431)
Retained earnings	114,292	175,688
Accumulated other comprehensive loss, net of income tax	(224)	---
	544,712	600,877
	$1,410,358	$1,517,288

See accompanying Notes to Consolidated Financial Statements.

Condensed Consolidated Statements of Operations (Unaudited)
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Three Months Ended		Six Months Ended	
	06/30/09	06/30/08	06/30/09	06/30/08
Revenues:				
Oil and gas sales	$82,783	$263,184	$159,201	$463,157
Price-risk management and other, net	138	(503)	79	(1,516)
	82,921	262,681	159,280	461,641
Costs and Expenses:				
General and administrative, net	7,581	10,291	16,000	20,210
Depreciation, depletion, and amortization	40,365	57,280	84,299	109,774
Accretion of asset retirement obligation	717	467	1,419	921
Lease operating cost	18,818	28,584	38,626	55,009
Severance and other taxes	9,908	26,856	18,594	48,992
Interest expense, net	7,813	8,231	15,280	16,921
Write-down of oil and gas properties	---	---	79,312	---
	85,202	131,709	253,530	251,827
Income (Loss) from Continuing Operations Before Income Taxes	(2,281)	130,972	(94,250)	209,814
Provision (Benefit) for Income Taxes	(71)	47,727	(33,037)	76,734
Income (Loss) from Continuing Operations	(2,210)	83,245	(61,213)	133,080
Loss from Discontinued Operations, net of taxes	(57)	(1,326)	(183)	(2,800)
Net Income (Loss)	$(2,267)	$81,919	$(61,396)	$130,280
Per Share Amounts-				
Basic: Income (Loss) from Continuing Operations	$(0.07)	$2.66	$(1.97)	$4.27
Loss from Discontinued Operations, net of taxes	(0.00)	(0.04)	(0.01)	(0.09)
Net Income (Loss)	$(0.07)	$2.61	$(1.97)	$4.18
Diluted: Income (Loss) from Continuing Operations	$(0.07)	$2.62	$(1.97)	$4.22
Loss from Discontinued Operations, net of taxes	(0.00)	(0.04)	(0.01)	(0.09)
Net Income (Loss)	$(0.07)	$2.58	$(1.97)	$4.13
Weighted Average Shares Outstanding	31,175	30,608	31,103	30,478

See accompanying Notes to Consolidated Financial Statements.

Condensed Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 2007	$306	$407,464	$(7,480)	$436,178	$ (414)	$836,054
Stock issued for benefit plans (39,152 shares)	-	1,018	671	-	-	1,689
Stock options exercised (420,721 shares)	4	8,295	-	-	-	8,299
Purchase of treasury shares (70,622 shares)	-	-	(3,622)	-	-	(3,622)
Tax benefits from stock compensation	-	1,422	-	-	-	1,422
Employee stock purchase plan (25,645 shares)	-	944	-	-	-	944
Issuance of restricted stock (275,096 shares)	3	(3)	-	-	-	-
Amortization of stock compensation	-	16,167	-	-	-	16,167
Comprehensive income:						
Net loss	-	-	-	(260,490)	-	(260,490)
Other comprehensive income	-	-	-	-	414	414
Total comprehensive loss						(260,076)
Balance, December 31, 2008	$313	$435,307	$(10,431)	$175,688	$ ---	$600,877
Stock issued for benefit plans (94,023 shares) (2)	-	(716)	2,094	-	-	1,378
Stock options exercised (7,730 shares) (2)	-	94	-	-	-	94
Purchase of treasury shares (44,093 shares) (2)	-	-	(657)	-	-	(657)
Tax benefits from stock compensation (2)	-	(1,823)	-	-	-	(1,823)
Employee stock purchase plan (50,690 shares) (2)	1	724	-	-	-	725
Issuance of restricted stock (212,561 shares) (2)	2	(2)	-	-	-	-
Amortization of stock compensation (2)	-	5,738	-	-	-	5,738
Comprehensive income:						
Net loss (2)	-	-	-	(61,396)	-	(61,396)
Other comprehensive loss (2)	-	-	-	-	(224)	(224)
Total comprehensive loss (2)						(61,620)
Balance, June 30, 2009 (2)	$316	$439,322	$(8,994)	$114,292	$ (224)	$544,712

(1) $.01 par value.
(2) Unaudited.

See accompanying Notes to Consolidated Financial Statements.

Condensed Consolidated Statements of Cash Flows (Unaudited)
Swift Energy Company and Subsidiaries

(in thousands)	Six Months Ended June 30, 2009	2008
Cash Flows from Operating Activities:		
Net income (loss)	$(61,396)	$130,280
Plus loss from discontinued operations, net of taxes	183	2,800
Adjustments to reconcile net income to net cash provided by operation activities -		
Depreciation, depletion, and amortization	84,299	109,774
Write-down of oil and gas properties	79,312	---
Accretion of asset retirement obligation	1,419	921
Deferred income taxes	(29,905)	73,730
Stock-based compensation expense	4,645	5,965
Other	10,162	(2,833)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	2,526	(31,948)
Increase (decrease) in accounts payable and accrued liabilities	(7,406)	6,493
Decrease in income taxes payable	(241)	(79)
Decrease in accrued interest	(25)	(360)
Cash Provided by operating activities – continuing operations	83,573	294,743
Cash Provided by (Used in) operating activities – discontinued operations	(337)	6,690
Net Cash Provided by Operating Activities	83,236	301,433
Cash Flows from Investing Activities:		
Additions to property and equipment	(135,801)	(318,962)
Proceeds from the sale of property and equipment	52	113
Cash Used in investing activities – continuing operations	(135,749)	(318,849)
Cash Provided by investing activities – discontinued operations	5,000	80,731
Net Cash Used in Investing Activities	(130,749)	(238,118)
Cash Flows from Financing Activities:		
Net proceeds from (payments of) bank borrowings	47,300	(62,800)
Net proceeds from issuances of common stock	818	7,313
Excess tax benefits from stock-based awards	---	1,083
Purchase of treasury shares	(657)	(1,387)
Cash Provided by (Used in) financing activities – continuing operations	47,461	(55,791)
Cash Provided by financing activities – discontinued operations	---	---
Net Cash Provided by (Used in) financing activities	47,461	(55,791)
Net Increase (Decrease) in Cash and Cash Equivalents	$(52)	$7,524
Cash and Cash Equivalents at Beginning of Period	283	5,623
Cash and Cash Equivalents at End of Period	$231	$13,147
Supplemental Disclosures of Cash Flows Information:		

Cash paid during period for interest, net of amounts capitalized	$14,579	$16,721
Cash paid during period for income taxes	$229	$3,005

See accompanying Notes to Consolidated Financial Statements.

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries

(1) General Information

The condensed consolidated financial statements included herein have been prepared by Swift Energy Company ("Swift Energy" or the "Company") and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying condensed consolidated financial statements include the accounts of Swift Energy and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas. Our undivided interests in gas processing plants are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying condensed consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying condensed consolidated financial statements.

Discontinued Operations. Unless otherwise indicated, information presented in the notes to the financial statements relates only to Swift Energy's continuing operations. Information related to discontinued operations is included in Note 6 and in some instances, where appropriate, is included as a separate disclosure within the individual footnotes.

Subsequent Events. We have evaluated subsequent events through the time of filing on August 3, 2009 of our condensed consolidated financial statements. In our Central Louisiana/East Texas core area, we recently entered into a joint venture agreement for development and exploitation in and around the Burr Ferry field in Vernon Parish, Louisiana. The Company, as fee mineral owner, leased a 50% working interest in approximately 33,623 gross acres and will retain a 50% working interest in the joint venture acreage and will also retain its fee mineral royalty rights. There were no other material subsequent events requiring additional disclosure in or amendments to these financial statements as of August 3, 2009.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
  - estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,

- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers and their ability to withstand the credit crisis,
- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations, and
- estimates in the calculation of the fair value of hedging assets.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the “full-cost” method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the six months ended June 30, 2009 and 2008, such internal costs capitalized totaled $12.1 million and $14.7 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the six months ended June 30, 2009 and 2008, capitalized interest on unproved properties totaled $3.0 million and $3.9 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and natural gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and natural gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization (“DD&A”) of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and natural gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and natural gas produced during the period by the total estimated units of proved oil and natural gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between three and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical (“G&G”) costs incurred on developed properties are recorded in “Proved properties” and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in “Unproved properties” and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at June 30, 2009 consisted of floors with strike prices lower than the period-end price and did not materially affect this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization ("DD&A") is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

In 2009, as a result of low oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million on our oil and natural gas properties. For 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a fourth quarter non-cash write-down on a before-tax basis of $754.3 million on our oil and natural gas properties.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near term. If oil and natural gas prices continue to decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that additional non-cash write-downs of oil and natural gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, additional non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of June 30, 2009, we did not have any material natural gas imbalances.

Reclassification of Prior Period Balances. Certain reclassifications have been made to prior period amounts to conform to the current year presentation.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, hedging assets, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair value of our hedging assets is detailed in Note 8. The fair values of the bank borrowings approximate the carrying amounts as of June 30, 2009 and December 31, 2008, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of June 30, 2009 and December 31, 2008, the fair value of our senior notes due 2017, were $180.6 million, or 72% of face value, and $175.0 million, or 70% of face value, respectively. Based upon quoted market prices as of June 30, 2009 and December 31, 2008, the fair values of our senior notes due 2011 were $142.5 million, or 95% of face value, and $132.8 million, or 88.5% of face value, respectively. The carrying value of our senior notes due 2017 was $250.0 million at June 30, 2009 and December 31, 2008. The carrying value of our senior notes due 2011 was $150.0 million at June 30, 2009 and December 31, 2008.

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At June 30, 2009 and December 31, 2008, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying condensed consolidated balance sheets.

Insurance Claims. In 2008, we filed insurance claims related to 2008 Hurricanes Gustav and Ike. In April 2009, we settled our marine insurance claim relating to Hurricane Gustav for a net amount after deductible of $6.75 million, which related to both capital costs and lease operating expense, and still have additional claims outstanding. We expect the remainder of costs for the projects to restore production capacity losses related to Hurricanes Gustav and Ike, primarily in the Bay de Chene field, will be completed in the third quarter of 2009 and mainly relate to capital projects.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the statement of operations and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price floors and collars. During the second quarter of 2009 and 2008, we recognized net losses of less than $0.1 million and $0.9 million, respectively, relating to our derivative activities. During the first six months of 2009 and 2008, we recognized net losses of less than $0.1 million and $1.9 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. Had these gains and losses been recognized in the oil and gas sales account they would not materially change our per unit sales prices received. At June 30, 2009, the Company had recorded $0.2 million, net of taxes of $0.1 million, of derivative losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying condensed consolidated balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for the first six months of 2009 and 2008 was not material. All amounts currently held in "Accumulated other comprehensive loss, net of income tax" will be realized within the next three months when the forecasted sale of hedged production occurs.

At June 30, 2009, we had oil price floors in effect for the contract months of July 2009 through September 2009 that cover a portion of our oil production for July 2009 to September 2009. The oil price floors cover notional volumes of 645,000 barrels, with a weighted average floor price of $62.00 per barrel. Our oil price floors in place at June 30, 2009 are expected to cover approximately 69% to 73% of our estimated oil production from July 2009 through September 2009.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive loss, net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive loss, net of income tax" and recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. The fair value of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at June 30, 2009, was $0.9 million and is recognized on the accompanying condensed consolidated balance sheet in "Other current assets."

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, to the extent they do not exceed actual costs incurred, are recorded as a reduction to “General and administrative, net.” Our supervision fees are based on COPAS determined rates. The amount of supervision fees charged in the first six months of 2009 and 2008 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $5.7 million and $7.8 million in the first six months of 2009 and 2008, respectively.

Inventories. We value inventories at the lower of cost or market value. Inventory is accounted for using the first in, first out method (“FIFO”). Inventories consisting of materials, supplies, and tubulars are included in “Other current assets” on the accompanying condensed consolidated balance sheets totaling $16.3 million at June 30, 2009 and $13.7 million at December 31, 2008.

Income Taxes. Under SFAS No. 109, “Accounting for Income Taxes,” deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. In the fourth quarter of 2008 we recorded additional tax expense and increased other long-term liabilities by $0.3 million, which increased our total balance of our unrecognized tax benefits to $1.3 million. If recognized, these tax benefits would fully impact our effective tax rate.

We do not believe the total of unrecognized tax benefits will significantly increase or decrease during the next 12 months.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of June 30, 2009, we have accrued $0.3 million for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns from 1998 through 2003 and 2005 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2002, and our Texas franchise tax returns after 2005 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

Accounts Payable and Accrued Liabilities. Included in “Accounts payable and accrued liabilities,” on the accompanying condensed consolidated balance sheets, at June 30, 2009 and December 31, 2008 are liabilities of approximately $4.8 million and $23.5 million, respectively, which represent the amounts by which checks issued, but not presented by vendors to the Company’s banks for collection, exceeded balances in the applicable disbursement bank accounts.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the provisions of SFAS No. 130, “Reporting Comprehensive Income,” which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At June 30, 2009, we recorded $0.2 million, net of taxes of $0.1 million, of derivative losses in “Accumulated other comprehensive loss, net of income tax” on the accompanying balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2009 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2008	$---	$---	$---
Change in fair value of cash flow hedges	(354)	131	(224)
Effect of cash flow hedges settled during the period	---	---	---
Other comprehensive loss at June 30, 2009	($354)	$131	($224)

Total comprehensive income (loss) was ($2.5) million and $80.3 million for the second quarters of 2009 and 2008, respectively. Total comprehensive income (loss) was ($61.6) million and $128.7 million for the six months of 2009 and 2008, respectively.

Asset Retirement Obligation. We record these obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the estimated oil and natural gas reserves of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the full cost balance. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation.

The following provides a roll-forward of our asset retirement obligation:

(in thousands)	2009	2008
Asset Retirement Obligation recorded as of January 1	$48,785	$34,459
Accretion expense for the six months ended June 30	1,420	921
Liabilities incurred for new wells and facilities construction	3,234	1,169
Reductions due to sold, or plugged and abandoned wells	(504)	(24)
Revisions in estimated cash flows	306	824
Asset Retirement Obligation as of June 30	$53,241	$37,349

At June 30, 2009 and December 31, 2008, approximately $6.6 million and $0, respectively, of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets.

New Accounting Pronouncements. In February 2008, the FASB delayed the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. This standard was adopted on January 1, 2009. The adoption of this statement did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. This statement requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity’s financial position, results of operations, and cash flows. This statement was effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Since this statement only impacts disclosure requirements, the adoption of this statement did not have an impact on our financial position or results of operations.

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 “Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities,” (“FSP EITF 03-6-1”). Under the FSP, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. This standard was adopted on January 1, 2009. The adoption of this statement did not have a material impact on our financial position, results of operations, or earnings per share.

In December 2008, the SEC issued release 33-8995, Modernization of Oil and Gas Reporting. This release changes the accounting and disclosure requirements surrounding oil and natural gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The most significant changes include:

- Changes to prices used in reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
- Disclosures of probable and possible reserves are allowed.
- The estimation of reserves will allow the use of reliable technology that was not previously recognized by the SEC.
- Numerous changes in reserves disclosures have been mandated for SEC Form 10-K.

This release is effective for financial statements issued for fiscal years and interim periods beginning on or after January 1, 2010.

In May 2009, the FASB issued SFAS No. 165, "Subsequent Events." SFAS No. 165 that establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We adopted SFAS No 165 for the period ending June 30, 2009; however the adoption of this statement did not have an impact on our financial position or results of operations.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008, for additional information related to these share-based compensation plans.

We follow SFAS No. 123R, "Share-Based Payment" to account for share based compensation.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. We receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the six months ended June 30, 2009, we recognized a tax benefit shortfall of $1.8 million as restricted stock vested at a lower value than the value used to record compensation expense at the date of grant, offset by a reduction to additional paid-in capital. For the six months ended June 30, 2008, these benefits were $3.2 million, of which $2.1 million were not recognized in the financial statements as these benefits had not been realized through the estimated alternative minimum tax calculation.

Net cash proceeds from the exercise of stock options were $0.1 million and $7.4 million for the six months ended June 30, 2009 and 2008. The actual income tax benefit from stock option exercises was less than $0.1 million and $3.5 million for the same periods.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees, which were recorded in "General and administrative, net" in the accompanying condensed consolidated statements of income, were $2.4 million and $3.1 million for the quarters ended June 30, 2009 and 2008, respectively, and were $4.1 million and $5.4 million for the six month periods ended June 30, 2009 and 2008. Stock compensation recorded in lease operating cost was $0.1 million and $0.2 million for the quarters ended June 30, 2009 and 2008, respectively, and were $0.2 million and $0.3 million for both of the six month periods ended June 30, 2009 and 2008, respectively. We also capitalized $0.7 million and $1.2 million of stock compensation in the second quarters of 2009 and 2008, respectively, and capitalized $1.1 million and $2.3 million of stock compensation in the six month periods ended June 30, 2009 and 2008, respectively. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the service period of the award.

Stock Options

We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods. No stock options were issued in the second quarter of 2009:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Month Ended June 30, 2009	Six Month Ended June 30, 2008
Dividend yield	N/A	0%	0%	0%
Expected volatility	N/A	38.4%	50.5%	38.9%
Risk-free interest rate	N/A	2.5%	1.8%	2.5%
Expected life of options (in years)	N/A	2.0	4.5	4.2
Weighted-average grant-date fair value	N/A	$13.89	$ 6.32	$15.53

The expected term for grants issued during or after 2008 has been based on an analysis of historical employee exercise behavior and considered all relevant factors including expected future employee exercise behavior. The expected term for grants issued prior to 2008 was calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility, and based on an analysis of all relevant factors, we have used a 5.5 year look-back period to estimate expected volatility of our 2008 and 2009 stock option grants, which is an increase from the four-year period used to estimate expected volatility for grants prior to 2008.

At June 30, 2009, there was $2.2 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.3 years. The following table represents stock option activity for the six months ended June 30, 2009:

	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	1,119,469	$ 33.22
Options granted	273,400	$ 14.66
Options canceled	(55,456)	$ 36.81
Options exercised	(7,730)	$ 12.02
Options outstanding, end of period	1,329,683	$ 29.27
Options exercisable, end of period	789,885	$ 30.54

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at June 30, 2009 was $1.4 million and 5.7 years and $0.8 million and 3.8 years, respectively. Total intrinsic value of options exercised during the six months ended June 30, 2009 was less than $0.1 million.

Restricted Stock

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of June 30, 2009, we had unrecognized compensation expense of approximately $9.8 million associated with these awards which are expected to be recognized over a weighted-average period of 2.0 years. The grant date fair value of shares vested during the six months ended June 30, 2009 was $9.1 million.

The following table represents restricted stock activity for the six months ended June 30, 2009:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	586,325	$ 42.78
Restricted shares granted	428,250	$ 12.38
Restricted shares canceled	(48,213)	$ 42.47
Restricted shares vested	(212,582)	$ 42.72
Restricted shares outstanding, end of period	753,780	$ 25.55

(4) Earnings Per Share

The Company adopted FASB Staff Position No. EITF 03-6-1 “Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities,” (“FSP EITF 03-6-1”) on January 1, 2009. Under the FSP, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. Unvested share-based payments that contain non-forfeitable rights to dividends or dividend equivalents are now included in the basic weighted average share calculation under the two-class method. These shares were previously included in the diluted weighted average share calculation under the treasury stock method.

As we recognized a net loss in the second quarter and first six months of 2009, these unvested share-based payments and stock options were not recognized in diluted earnings per share (“Diluted EPS”) calculations as they would be antidilutive. Diluted EPS for the 2008 period also assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the three and six month periods ended June 30, 2009 and 2008, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and six month periods ended June 30, 2009 and 2008 (in thousands, except per share amounts):

	Three Months Ended June 30, 2009			Three Months Ended June 30, 2008		
	Loss from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount
Basic EPS:						
Income (Loss) from continuing operations, and Share Amounts	$(2,210)	31,175		$83,245	30,608	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	---	---		$(1,913)	---	
Income (Loss) from continuing operations allocated to common shares	$(2,210)	31,175	$(0.07)	$81,332	30,608	$2.66
Dilutive Securities:						
Plus: Income (Loss) from continuing operations allocated to unvested shareholders	---	---		$1,913	---	
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders	---	---		$(1,889)	---	
Stock Options	---	---		---	403	
Diluted EPS:						
Income (Loss) from continuing operations allocated to	$(2,210)	31,175	$(0.07)	$81,356	31,011	$2.62

common shares,
and assumed
Share conversions

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	Six Months Ended June 30, 2009			Six Months Ended June 30, 2008		
	Loss from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount
Basic EPS:						
Income (Loss) from continuing operations, and Share Amounts	$(61,213)	31,103		$133,080	30,478	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	---	---		$(2,959)	---	
Income (Loss) from continuing operations allocated to common shares	$(61,213)	31,103	$(1.97)	$130,121	30,478	$4.27
Dilutive Securities:						
Plus: Income (Loss) from continuing operations allocated to unvested shareholders	---	---		$2,959	---	
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders	---	---		$(2,925)	---	
Stock Options	---	---		---	355	
Diluted EPS:						
Income (Loss) from continuing operations allocated to common shares, and assumed Share	$(61,213)	31,103	$(1.97)	$130,155	30,833	$4.22

conversions

The adoption of FSP EITF 03-6-1 lowered our second quarter 2008 Basic EPS and Diluted EPS for continuing operations by $0.06 per share and $0.04 per share, respectively, from previously reported amounts, and lowered our first six months of 2008 Basic EPS and Diluted EPS for continuing operations by $0.10 per share and $0.05 per share, respectively, from previously reported amounts. Options to purchase approximately 1.3 million shares at an average exercise price of $29.27 were outstanding at June 30, 2009, while options to purchase 1.2 million shares at an average exercise price of $32.90 were outstanding at June 30, 2008. All of the 1.3 million stock options to purchase shares outstanding at June 30, 2009 were not included in the computation of Diluted EPS for the three and six month periods ended June 30, 2009, as they would be antidilutive given the net loss from continuing operations. Approximately 0.8 million stock options to purchase shares were not included in the computation of Diluted EPS for the three and six month periods ended March 31, 2008, because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods.

The effect of the adoption of FSP EITF 03-6-1 on prior year earnings per share from previously reported amounts, as stated in our Annual Report on Form 10-K for the year ended December 31, 2008, 2007, and 2006, were as follows: no effect for full-year 2008, lower Basic EPS and Diluted EPS from continuing operations for full-year 2007 by $0.11 per share and $0.07 per share, respectively, lower Basic EPS and Diluted EPS from continuing operations for full-year 2006 by $0.06 per share and $0.03 per share, respectively.

(5) Long-Term Debt

Our long-term debt as of June 30, 2009 and December 31, 2008, was as follows (in thousands):

	June 30, 2009	December 31, 2008
Bank Borrowings	$228,000	$180,700
7-5/8% senior notes due 2011	150,000	150,000
7-1/8% senior notes due 2017	250,000	250,000
Long-Term Debt	$628,000	$580,700

Bank Borrowings. At June 30, 2009, we had borrowings of $228.0 million under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base of $300.0 million, and expires in October 2011. In May 2009, in conjunction with the normal semi-annual review, our borrowing base and commitment amount were set at $300.0 million. This was a decrease from the previous borrowing base of $400.0 million and commitment amount of $350.0 million but still in line with our 2009 cash needs. Effective May 1, 2009, the interest rate is either (a) the lead bank's prime rate plus applicable margin or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margins have increased to escalating rates of 100 to 250 basis points above the lead bank's prime rate and escalating rates of 200 to 350 basis points for LIBOR rate loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At June 30, 2009, the lead bank's prime rate was 3.25%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt, or absent permitted refinancing, repurchasing our 7-5/8% senior notes due 2011. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and natural gas properties. The borrowing base amount is re-determined at least every six months and the next scheduled borrowing base review is in November 2009.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.8 million and $2.6 million for the three months ended June 30, 2009 and 2008, respectively, and $3.2 million and $5.4 million for the six months ended June 30, 2009 and 2008, respectively. The amount of commitment fees included in interest expense, net was $0.1 million for each of the three month periods ended June 30, 2009 and 2008, respectively, and $0.2 million for each of the six month periods ended June 30, 2009 and 2008.

Senior Notes Due 2011. These notes consist of $150.0 million of 7-5/8% senior notes, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005.

On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in “Debt issuance costs” on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $3.0 million for each of the three month periods ended June 30, 2009 and 2008, respectively, and $6.0 million for each of the six month periods ended June 30, 2009 and 2008.

Senior Notes Due 2017. These notes consist of $250.0 million of 7-1/8% senior notes due 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, commencing on December 1, 2007. On or after June 1, 2012, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 2015 and thereafter. In addition, prior to June 1, 2010, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.125% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in “Debt issuance costs” on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $4.5 million for each of the three month periods ended June 30, 2009 and 2008, respectively, and $9.1 million for each of the six month periods ended June 30, 2009 and 2008, respectively.

The maturities on our long-term debt are $0 for 2009 and 2010, $378.0 million for 2011, $0 for 2012, and $250 million thereafter.

We have capitalized interest on our unproved properties in the amount of $1.5 million and $2.0 million for the three months ended June 30, 2009 and 2008, respectively, and $3.0 million and $3.9 million for the six month periods ended June 30, 2009 and 2008, respectively.

(6) Discontinued Operations

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the condensed consolidated Statements of Operations and cash flows and the assets and associated liabilities have been classified as held for sale in the condensed consolidated balance sheets. In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending final resolution of this litigation.

In February 2009, the first $5.0 million payment from the sale of our last permit was released to our attorneys who were holding these proceeds in trust for Swift Energy. In April 2009, after an injunction limiting our ability to use such funds was dismissed in favor of Swift Energy, the proceeds were transferred to our bank account in the United States.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheets. During the first half of 2008, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement in place at that time and recorded a non-cash asset write-down of $3.3 million related to these assets. This write-down is recorded in "Loss from discontinued operations, net of taxes" on the accompanying condensed consolidated Statements of Operations.

The book value of our remaining New Zealand permit is approximately $0.6 million at June 30, 2009.

The following table summarizes the amounts included in "Income (loss) from discontinued operations, net of taxes" for all periods presented. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported as discontinued operations (in thousands except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Oil and gas sales	$ ---	$ 6,370	$ ---	$ 14,675
Other revenues	(1)	207	20	781
Total revenues	$ (1)	6,577	$ 20	15,456
Depreciation, depletion, and amortization	---	2,289	---	4,909
Other operating expenses	127	4,241	203	10,136
Non-cash write-down of property and equipment	---	1,200	---	3,296
Total expenses	$ 127	7,730	$ 203	18,341
Loss from discontinued operations before income taxes	(128)	(1,153)	(183)	(2,885)
Income tax expense (benefit)	(71)	173	---	(85)
Loss from discontinued operations, net of taxes	$ (57)	$ (1,326)	$ (183)	$ (2,800)
Loss per common share from discontinued operations-diluted	$ (0.00)	$ (0.04)	$ (0.01)	$ (0.09)
Sales volumes (MBoe)	---	167	---	415
Cash flow provided by operating activities	$ (93)	$ 3,868	$ (337)	$ 6,690
Capital expenditures	$ ---	$ 990	$ ---	$ 2,013

(7) Acquisitions and Dispositions

In August 2008, we announced the acquisition of oil and natural gas interests in South Texas from Crimson Energy Partners, L.P. a privately held company. The property interests are located in the Briscoe "A" lease in Dimmit County. Including an accrual of $0.6 million for purchase price adjustment reductions, we paid approximately $45.9 million in cash for these interests. After taking into account internal acquisition costs of $1.5 million, our total cost was $47.4 million. We allocated $44.0 million of the acquisition price to "Proved Properties," $3.4 million to "Unproved Properties," and recorded a liability for $0.2 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Texas. The revenues and expenses from these properties have been included in our accompanying consolidated statement of income from the date of acquisition forward and due to the short time period are not material to our 2008 results.

(8) Fair Value Measurements

We adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements," for financial assets and liabilities on January 1, 2008 and adopted the provisions for non-financial assets and liabilities on January 1, 2009. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosure about fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements. The adoption of this statement did not have a material impact on our financial position or results of operations.

The following tables present our assets that are measured at fair value on a recurring basis during the six months ended June 30, 2009 and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value.

The table below presents a reconciliation for assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the three months ended June 30, 2009 (in millions):

Fair Value Reconciliation as of June 30, 2009 – three months QTD	Hedging Contracts
Balance as of March 31, 2009	$0.0
Total gains/(losses) (realized or unrealized):	
Included in earnings	0.0
Included in other comprehensive income	(0.4)
Purchases, issuances and settlements	1.3
Transfers in and out of Level 3	---
Balance as of June 30, 2009	$0.9
The approximate amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to derivatives still held at June 30, 2009	$0.0

The table below presents a reconciliation for assets measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the six months ended June 30, 2009 (in millions):

Fair Value Reconciliation as of June 30, 2009 – six months YTD	Hedging Contracts
Balance as of December 31, 2008	$0.0
Total gains/(losses) (realized or unrealized):	
Included in earnings	0.0
Included in other comprehensive income	(0.4)
Purchases, issuances and settlements	1.3
Transfers in and out of Level 3	---
Balance as of June 30, 2009	$0.9
The approximate amount of total gains for the period included in earnings attributable to the change in unrealized gains relating to derivatives still held at June 30, 2009	$0.0

(9) Condensed Consolidateing Financial Information

Both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) are co-obligors of the 7-5/8% Senior Notes due 2011. The co-obligations on these notes are full and unconditional and are joint and several. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and other subsidiaries:

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Condensed Consolidating Balance Sheets

(in thousands)	June 30, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 72,005	$ 681	$ ---	$ 72,686
Property and equipment	---	1,330,751	---	---	1,330,751
Investment in subsidiaries (equity method)	544,712	---	473,225	(1,017,937)	---
Other assets	---	6,921	75,842	(75,842)	6,921
Total assets	$ 544,712	$ 1,409,677	$ 549,748	$ (1,093,779)	$ 1,410,358
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 76,608	$ 5,036	$ ---	$ 81,644
Long-term liabilities	---	859,844	---	(75,842)	784,002
Stockholders' equity	544,712	473,225	544,712	(1,017,937)	544,712
Total liabilities and stockholders' equity	$ 544,712	$ 1,409,677	$ 549,748	$ (1,093,779)	$ 1,410,358

(in thousands)	December 31, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 77,323	$ 763	$ ---	$ 78,086
Property and equipment	---	1,431,447	---	---	1,431,447
Investment in subsidiaries (equity method)	600,877	---	529,209	(1,130,086)	---

Other assets	---	7,755	71,089	(71,089)	7,755
Total assets	$ 600,877	$ 1,516,525	$ 601,061	$ (1,201,175)	$ 1,517,288
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 153,315	$ 184	$ ---	$ 153,499
Long-term liabilities	---	834,001	---	(71,089)	762,912
Stockholders' equity	600,877	529,209	600,877	(1,130,086)	600,877
Total liabilities and stockholders' equity	$ 600,877	$ 1,516,525	$ 601,061	$ (1,201,175)	$ 1,517,288

Condensed Consolidating Statements of Operations

(in thousands)	Three Months Ended June 30, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 82,921	$ ---	$ ---	$ 82,291
Expenses	---	85,202	---	---	85,202
Loss before the following:	---	(2,281)	---	---	(2,281)
Equity in net earnings of subsidiaries	(2,267)	---	(2,210)	4,477	---
Loss from continuing operations, before income taxes	(2,267)	(2,281)	(2,210)	4,477	(2,281)
Income tax benefit	---	(71)	---	---	(71)
Loss from continuing operations	(2,267)	(2,210)	(2,210)	4,477	(2,210)
Loss from discontinued operations, net of taxes	---	---	(57)	---	(57)
Net loss	$ (2,267)	$ (2,210)	$ (2,267)	$ 4,477	$ (2,267)

(in thousands)	Six Months Ended June 30, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 159,280	$ ---	$ ---	$ 159,280
Expenses	---	253,530	---	---	253,530
Loss before the following:	---	(94,250)	---	---	(94,250)
Equity in net earnings of subsidiaries	(61,396)	---	(61,213)	122,609	---
Loss from continuing operations, before income taxes	(61,396)	(94,250)	(61,213)	122,609	(94,250)
Income tax benefit	---	(33,037)	---	---	(33,037)
Loss from continuing operations	(61,396)	(61,213)	(61,213)	122,609	(61,213)
Loss from discontinued operations, net of taxes	---	---	(183)	---	(183)
Net loss	$ (61,396)	$ (61,213)	$ (61,396)	$ 122,609	$ (61,396)

(in thousands)	Three Months Ended June 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 262,681	$ ---	$ ---	$ 262,681
Expenses	---	131,709	---	---	131,709
Income before the following:	---	130,972	---	---	130,972
Equity in net earnings of subsidiaries	81,919	---	83,245	(165,164)	---
Income from continuing operations,	81,919	130,972	83,245	(165,164)	130,972

before income taxes					
Income tax provision	---	47,727	---	---	47,727
Income from continuing operations	81,919	83,245	83,245	(165,164)	83,245
Loss from discontinued operations, net of taxes	---	---	(1,326)	---	(1,326)
Net income	$ 81,919	$ 83,245	$ 81,919	$ (165,164)	$ 81,919

(in thousands)	Six Months Ended June 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 461,641	$ ---	$ ---	$ 461,641
Expenses	---	251,827	---	---	251,827
Income before the following:	---	209,814	---	---	209,814
Equity in net earnings of subsidiaries	130,280	---	133,080	(263,360)	---
Income from continuing operations, before income taxes	130,280	209,814	133,080	(263,360)	209,814
Income tax provision	---	76,734	---	---	76,734
Income from continuing operations	130,280	133,080	133,080	(263,360)	133,080
Loss from discontinued operations, net of taxes	---	---	(2,800)	---	(2,800)
Net income	$ 130,280	$ 133,080	$ 130,280	$ (263,360)	$ 130,280

Condensed Consolidating Statements of Cash Flow

(in thousands)	Six Months Ended June 30, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 83,573	$ (337)	$ ---	$ 83,236
Cash flow from investing activities	---	(131,007)	5,000	(4,742)	(130,749)
Cash flow from financing activities	---	47,461	(4,742)	4,742	47,461
Net increase (decrease) in cash	---	27	(79)	---	(52)
Cash, beginning of period	---	87	196	---	283
Cash, end of period	$ ---	$ 114	$ 117	$ ---	$ 231

(in thousands)	Six Months Ended June 30, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 294,743	$ 6,690	$ ---	$ 301,433
Cash flow from investing activities	---	(236,936)	80,731	(81,913)	(238,118)
Cash flow from financing activities	---	(55,791)	(81,913)	81,913	(55,791)
Net increase in cash	---	2,016	5,508	---	7,524
Cash, beginning of period	---	180	5,443	---	5,623
Cash, end of period	$ ---	$ 2,196	$ 10,951	$ ---	$ 13,147

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF
FINANCIAL CONDITION AND RESULTS OF OPERATIONS
SWIFT ENERGY COMPANY AND SUBSIDIARIES

Item 2.

You should read the following discussion and analysis in conjunction with our financial information and our condensed consolidated financial statements and notes thereto included in this report and our Annual Report on Form 10-K for the year ended December 31, 2008. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 39 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from the inland waters of Louisiana and from our onshore Louisiana and Texas properties.

We are one of the largest producers of crude oil in the state of Louisiana, and due to increasing emphasis on our South Louisiana operations, oil constitutes 46% of our second quarter of 2009 production, and together with our natural gas liquids ("NGLs") production makes up 59% of our total production for the second quarter. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in the second quarter of 2009.

Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our discontinued New Zealand operations.

Second Quarter 2009 Oil and Natural Gas Pricing

Recent extreme volatility in worldwide credit and financial markets, combined with significantly reduced prices for oil and natural gas, all of which began late in the third quarter of 2008, have had a significant impact on our cash flow, capital expenditures, and liquidity over the past nine months. Both oil and natural gas prices we received in the second quarter of 2009 were lower than the average prices we received in the second quarter of 2008, with a 62% decline in average prices per BOE received. These declines reduced our cash flow from operations in our most recent quarter and will continue to reduce our cash flow from operations in future periods in which prices remain at these lower levels.

Second quarter 2009 oil prices increased 35% over first quarter 2009 levels, while natural gas prices declined 26%, resulting in a 14% increase in average prices per BOE in the second quarter of 2009.

Actions taken in response to the credit crisis and downturn in the industry

The Company has taken several steps to manage the decline in expected cash flow in 2009 and provide liquidity in future periods including:

- Reduced 2009 budgeted capital expenditures when compared to our 2008 total capital costs incurred of $646 million (including acquisitions). We originally set a budgeted range of $125 to $150 million; and have recently increased this amount to $160 to $180 million. We have spent $63.7 million in the first half of 2009, primarily related to the completion of projects begun in 2008. To the extent our budgeted capital expenditures exceed our expected cash flows from operating activities for 2009 we have availability under our credit facility.

- Released all drilling rigs in early 2009. We did not spud any wells in the first quarter of 2009. We began drilling again in the second quarter of 2009 on a limited basis, as drilling costs have decreased moderately and become more in line with the current oil and gas pricing environment and expect to drill a number of wells in the third and fourth quarter of 2009 in line with our raised capital expenditure budget.
- Reduced our workforce. In early 2009, we reduced our workforce to lower general and administrative costs in future periods.
- Reduced our field lease operating expenses.
- Continued our review of the credit worthiness of customers. We believe that the risk of the unsecured receivables from purchasers of our oil and gas production is mitigated by the size, reputation, and nature of the companies to which we extend credit, along with letters of credit or parent company guaranties required from certain customers.
- Re-determined our bank credit facility. Our borrowing base and commitment amount in May 2009 was set at $300 million, a decrease from our previous borrowing base of $400 million and commitment amount of $350 million, with the new amounts in line with our projected 2009 cash needs.

Financial Condition

Our debt to capitalization ratio increased to 54% at June 30, 2009, as compared to 49% at year-end 2008, as total equity and retained earnings decreased due to our net loss for the six months ended June 30, 2009, which included a non-cash write-down of our oil and gas properties.

Operating Results- Prior Year Comparison

In the second quarter of 2009 we had revenues of $82.9 million, a decrease of 68% compared to 2008 levels. Our weighted average sales price received decreased 62% to $36.71 per Boe for the second quarter of 2009 from $97.70 per Boe in the same 2008 period. This $179.8 million decrease in revenues from second quarter 2008 levels resulted from lower oil, natural gas, and NGL prices during the second quarter of 2009, along with a 16% decrease in production mainly due to natural declines in our Lake Washington field.

Our loss from continuing operations for the second quarter of 2009 was $2.2 million compared to income from continuing operations of $83.2 million in the second quarter of 2008.

Our overall costs and expenses decreased in the second quarter of 2009 by $46.5 million, when compared to 2008 levels. Severance and other taxes decreased 63% mainly due to decreased oil and gas revenues. Depreciation, depletion and amortization expense also decreased 30%, mainly due to our lower depletable property base in the 2009 period as we incurred significant non-cash write-downs of oil and gas properties in the fourth quarter of 2008 and first quarter of 2009, lower production in the 2009 period, and lower future development costs in the 2009 period, partially offset by a reduction in reserves volumes when compared to the 2008 period. Lease operating costs decreased by 34% due to less workover costs, decreased natural gas processing costs, and a decrease in plant operating expense resulting from targeted cost reduction initiatives. We expect the market forces that were putting upward pressure on production costs in early 2008 to continue to soften as activity levels decline in response to falling commodity prices and current conditions in the financial markets. In 2009, we will continue to focus upon our capital efficiency to fully manage our costs and expenses.

Our loss from continuing operations for the first half of 2009 was $61.2 million ($11.2 million after-tax if the $79.3 million ($50.0 million after tax) first quarter non-cash write-down of our oil and gas properties is excluded), compared to income from continuing operations of $133.1 million in the first half of 2008.

Operating Results - Sequential Quarter Comparison

Our second quarter 2009 continuing operations revenues of $82.9 million increased 9% over comparable first quarter 2009 levels. Our weighted average sales price received increased 14% to $36.71 per Boe for the second quarter of 2009 from $32.29 per Boe in the first quarter of 2009. Our $6.6 million increase in revenues resulted from higher oil and NGL prices during the second quarter of 2009, partially offset by lower natural gas prices and a 5% decrease in production when compared to first quarter 2009 levels.

Our loss from continuing operations for the second quarter of 2009 was $2.2 million compared to a loss from continuing operations of $59.0 million in the first quarter of 2009. Excluding the first quarter 2009 non-cash write-down of oil and gas properties on a before-tax basis of $79.3 million ($50.0 million after tax), our loss from continuing operations after taxes was $9.0 million for the first quarter of 2009.

Our overall costs and expenses decreased in the second quarter of 2009 by $83.1 million, when compared to first quarter 2009 levels, mainly due to the absence of a $79.3 million non-cash write-down of oil and gas properties that took place in the first quarter of 2009. Depreciation, depletion and amortization expense also decreased by $3.6 million in the second quarter of 2009, mainly due to our lower depletable property base for that quarter resulting from the first quarter write-down and lower future development costs in the second quarter 2009.

Operating Activities

In the Company's South Texas core area, the first well of our 2009 horizontal drilling and completion program targeting the Olmos formation at the AWP field recently finished drilling and is being prepared for completion. The rig that drilled this well will soon be moved to begin drilling operations on the second well of the program. With the planned increase in capital spending for 2009, this Olmos horizontal drilling program will be continued into 2010, and a number of shallow oil locations will also be drilled in the AWP area.

Additionally, the Company is preparing to drill at least one horizontal well during the second half of the year to test the Eagle Ford shale formation in its AWP field. Swift Energy is also considering a strategic joint venture with an industry partner to accelerate the Eagle Ford development and increase the value of its existing acreage position.

We have continued to expand our acreage position in South Texas during 2009. The following is the Company's approximate undeveloped acreage position in the South Texas area as of July 31, 2009:

		Undeveloped (1)			
		Olmos Formation		Eagle Ford Formation	
County	Field	Gross Acres	Net Acres	Gross Acres	Net Acres
McMullen	AWP	37,000	37,000	60,000	60,000
La Salle	Sun TSH	17,000	15,000	8,000	8,000
Dimmitt	Briscoe	61,000	61,000	12,000	12,000
Webb	Fasken	0	0	9,000	9,000
Total Acres		115,000	113,000	89,000	89,000

(1) Includes surface acreage where our ownership interests i both formations overlap.

In our Central Louisiana/East Texas core area, we recently entered into a joint venture agreement with Anadarko E&P Company LP for development and exploitation in and around the Burr Ferry field in Vernon Parish, Louisiana. The Company, as fee mineral owner, leased a 50% working interest in approximately 33,623 gross acres to Anadarko. Swift Energy will retain a 50% working interest in the joint venture acreage and will also retain its fee mineral royalty rights.

At Lake Washington during the quarter, a production optimization program involving gas lift enhancements and sliding sleeve shifts to change productive zones was continued to assist in mitigation of natural field declines. Well work was completed on 13 wells and 3 recompletions were performed during the second quarter.

In our Southeast Louisiana and South Louisiana core areas we have completed 2400 square miles, of 3D prestack seismic depth migration over our Lake Washington, Shasta, and Bay de Chene fields. This depth migration and updated "salt model" has significantly improved and refined our understanding of the complex traps associated with salt bodies and will enable us to more accurately plan and position our exploratory and development wells. This seismic processing combined with seismic pore pressure prediction has allowed us to increase our confidence in well planning and drilling of wells that are deeper and larger in our Southeast Louisiana and South Louisiana areas. The improved seismic image in our Southeast Louisiana and South Louisiana core areas described above has delivered additional high value prospects which could be drilled later this year or next depending upon the commodity pricing environment.

Our Lake Washington field has experienced reservoir pressure issues in certain reservoirs for some time. In 2008, permits were submitted to the State of Louisiana to provide additional water injection into certain Newport reservoirs for pressure maintenance. However, based on recent results and ongoing reservoir simulation modeling, we do not anticipate that pressure maintenance activities will be fully commenced in 2009, and therefore do not expect any production increase from such activities during the year. Multi-disciplinary work is ongoing to determine optimized depletion plans for these reservoirs.

We have spent considerable time and capital on facility capacity upgrades and additions in the Lake Washington field. Our fourth production platform, the Westside facility, was commissioned in the second quarter of 2008. In the first quarter of 2009 the through-put capacity of this facility was doubled to 20,000 barrels of oil per day and 40 MMCF of gas per day. As a result of this expansion, and continued production decline in older portions of the field, production from our SL 212 facility was redirected to Westside. This will result in a reduction in lease operating expenses as the Westside facilities are newer and require less maintenance. The expanded capacity at the Westside facilities was also utilized to process production from our SL 18669 #1 (Shasta) well starting in late April 2009.

In the third quarter of 2008, our Bay de Chene field experienced significant damage to its production facilities from Hurricane Gustav, and some production equipment in the field was damaged or destroyed. Also in the third quarter of 2008, Hurricane Ike caused damage to several fields in our South Louisiana core area and our High Island field due to high water levels. In April 2009, we settled our marine insurance claim relating to Hurricane Gustav for a net amount after deductible of $6.75 million, which related to both capital costs and lease operating expense, and still have additional claims outstanding. We expect the remainder of costs for the projects to restore production capacity losses related to Hurricanes Gustav and Ike, primarily in the Bay de Chene field, will be completed in the third quarter of 2009 and mainly relate to capital projects.

New production facilities for our Bay de Chene field are being constructed and will be installed in the third quarter of 2009. Currently, only high pressure gas is being produced from the field through the old high pressure gas system. Oil and low pressure gas production will be reinstated after the new facilities are installed. We estimate that 1,500 to 2,000 net Boe per day remain shut in due to damage from Hurricane Gustav.

Capital Expenditures

Our capital expenditures on a cash flow basis during the first half of 2009 were $135.8 million, while our accrual based capital expenditures were $63.7 million, as during the first quarter we paid significant accounts payable and accrued capital cost balances incurred prior to year-end 2008. This cash flow basis amount decreased by $183.2 million as compared to the 2008 period, primarily due to a decrease in our spending on drilling and development, predominantly in our Southeast Louisiana and South Texas core areas. These 2009 expenditures were funded by $83.6 million of cash provided by operating activities from continuing operations, $47.3 million in proceeds from our line of credit borrowings, and $5.0 million in cash provided by investing activities – discontinued operations.

Given the current oil and gas pricing environment, our presently budgeted 2009 capital expenditures range between $160 million to $180 million, net of minor non-core dispositions and excluding any property acquisitions we might make. Based upon current market conditions and our estimates, our capital expenditures for 2009 will likely exceed our anticipated cash flow from operations and we have sufficient availability under our credit facility to fund a portion of these expenditures. For 2009, due to our reduced capital budget when compared to previous years, we anticipate a decrease in production volumes from 2008 levels, and we will not fully replace reserves produced in 2009. We may also increase our capital expenditure budget if commodity prices rise during the remainder of the year or if strategic acquisition opportunities arise.

Our 2009 capital expenditures are expected to include a continuation into 2010 of the horizontal well drilling program in the Olmos sands in our AWP field following the initial three well program, beginning an ongoing horizontal well program in the Eagle Ford shale formation in the AWP area that would also continue into 2010, renewing our drilling activity in Lake Washington by beginning at least a 10 well program targeting shallow and intermediate depth oil prospects that are part of our proved undeveloped and probable/possible inventory, continuing the recompletion program in our Southeast Louisiana core area and the fracture enhancement program in our South Texas core area, completing facility projects in our Bay de Chene field as well as drilling some shallow wells in our AWP field targeting primarily oil reservoirs.

Results of Continuing Operations — Three Months Ended June 30, 2009 and 2008

Revenues. Our revenues in the second quarter of 2009 decreased by 68% compared to revenues in the same period in 2008, mainly due to lower commodity prices. Revenues for both periods were substantially comprised of oil and gas sales. Crude oil production was 46% of our production volumes in the second quarter of 2009 and 55% of our production in the second quarter of 2008. Natural gas production was 41% of our production volumes in the second quarter of 2009 and 34% in the second quarter of 2008.

Our properties are divided into the following core areas: The Southeast Louisiana core area includes the Lake Washington and Bay de Chene fields. The Central Louisiana/East Texas core area includes the Brookeland, Masters Creek, South Bearhead Creek, and Chunchula fields. The South Louisiana core area includes the Cote Blanche Island, Horseshoe Bayou/Bayou Sale, Jeanerette, High Island, and Bayou Penchant fields. The South Texas core area includes the AWP, Briscoe Ranch, Las Tiendas, and Sun TSH fields. The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the three months ended June 30, 2009 and 2008:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (MBoe)	
	2009	2008	2009	2008
S. E. Louisiana	$50.8	$165.3	1,185	1,470
South Texas	17.2	47.3	669	678
Central Louisiana / E. Texas	9.6	26.7	233	269
South Louisiana	5.0	22.7	161	262
Strategic Growth	0.2	1.2	7	15
Total	$82.8	$263.2	2,255	2,694

Oil and gas sales for the second quarter of 2009 decreased by 69%, or $180.4 million, from the level of those revenues for the comparable 2008 period, and our net sales volumes in the second quarter of 2009 decreased by 16%, or 0.4 MMBoe, over net sales volumes in the second quarter of 2008. Average prices for oil decreased to $55.42 per Bbl in the second quarter of 2009 from $125.20 per Bbl in the second quarter of 2008. Average natural gas prices decreased to $3.11 per Mcf in the second quarter of 2009 from $10.49 per Mcf in the second quarter of 2008. Average NGL prices decreased to $28.26 per Bbl in the second quarter of 2009 from $67.73 per Bbl in the second quarter of 2008.

In the second quarter of 2009, our $180.4 million decrease in oil, NGL, and natural gas sales, compared to second quarter sales a year earlier, resulted from:

- Price variances that had a $124.5 million unfavorable impact on sales, of which $71.6 million was attributable to the 56% decrease in average oil prices received, $12.2 million was attributable to the 58% decrease in NGL prices, and $40.7 million was attributable to the 70% decrease in natural gas prices; and
- Volume variances that had a $55.9 million unfavorable impact on sales, with $57.0 million of decreases attributable to the 0.5 million Bbl decrease in oil sales volumes, a $0.1 million decrease due to the less than 0.1 Bcf decrease in natural gas sales volumes, partially offset by a $1.2 million increase due to the less than 0.1 million Bbl increase in NGL sales volumes.

The following table provides additional information regarding our quarterly oil and gas sales from continuing operations excluding any effects of our hedging activities:

	Sales Volume	Average Sales Price

	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural gas (Mcf)
Three months Ended June 30, 2009	1,026	308	5.5	2,255	$55.42	$28.26	$3.11
Three months Ended June 30, 2008	1,482	290	5.5	2,694	$125.20	$67.73	$10.49

During the second quarters of 2009 and 2008, we recognized net losses of less than $0.1 million and $0.9 million, respectively, related to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of operations. Had these losses been recognized in the oil and gas sales account, our average oil sales price would have been $0.01 and $0.05 per barrel lower for the second quarters of 2009 and 2008, respectively, and our average natural gas sales price would have been the same and $0.15 per Mcf lower for the second quarters of 2009 and 2008, respectively.

Costs and Expenses. Our expenses in the second quarter of 2009 decreased $46.5 million, or 35%, compared to expenses in the same period of 2008.

Our second quarter 2009 general and administrative expenses, net, decreased $2.7 million, or 26%, from the level of such expenses in the same 2008 period. The decrease was primarily due to decreased stock compensation and salaries and burdens related to a reduction in workforce during the first quarter of 2009. For the second quarters of 2009 and 2008, our capitalized general and administrative costs totaled $5.7 million and $7.9 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.36 per Boe in the second quarter of 2009 from $3.82 per Boe in the second quarter of 2008. The portion of supervision fees recorded as a reduction to general and administrative expenses was $2.8 million and $3.9 million for three month periods ended June 30, 2009 and 2008, respectively.

DD&A decreased $16.9 million, or 30%, in the second quarter of 2009 from levels in the second quarter of 2008. The decrease is mainly due to decreases in the depletable oil and gas property base due to the non-cash write-down of oil and gas properties in the fourth quarter of 2008 and first quarter of 2009, lower production volumes, and lower future development costs, partially offset by a reduction in reserves volumes when compared to the 2008 period. Our DD&A rate per Boe of production was $17.90 and $21.26 in the second quarters of 2009 and 2008, respectively.

We recorded $0.7 million and $0.5 million of accretions to our asset retirement obligation in the second quarters of 2009 and 2008, respectively.

Our lease operating costs decreased $9.8 million, or 34%, from the level of such expenses in the same 2008 period. Lease operating costs decreased during 2009 due to decreased workover costs, lower natural gas and NGL processing costs, and lower plant operating costs in 2009 resulting from targeted cost reduction initiatives. Our lease operating costs per Boe produced were $8.34 and $10.61 in the second quarters of 2009 and 2008, respectively.

Severance and other taxes decreased $16.9 million, or 63%, from levels in the second quarter of 2008. The decrease in the 2009 period was due primarily to decreased oil and gas revenues that resulted from lower commodity prices. Severance and other taxes as a percentage of oil and gas sales were approximately 12.0% and 10.2% in the second quarters of 2009 and 2008, respectively. The percentage increase was due to an increase in the severance tax rate of Louisiana gas, partially offset by a shift in the production mix from South Louisiana, which has a 12.5% oil severance tax rate.

Our total interest cost in the second quarter of 2009 was $9.3 million, of which $1.5 million was capitalized. Our total interest cost in the second quarter of 2008 was $10.2 million, of which $2.0 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense was primarily due to lower interest rates on our line of credit, partially offset by increased borrowings against our line of credit facility during the 2009 period.

Our overall effective tax rate was 3.1% and 36.4% for the second quarters of 2009 and 2008, respectively. The tax rate for the second quarter of 2009 was 3.1% due to a year-to-date cumulative effective rate decrease coupled with significantly lower income before taxes when compared to prior periods. The tax rate for the second quarter of 2008 was higher than the U.S. federal statutory rate of 35% primarily because of state income taxes.

Income (Loss) from Continuing Operations. Our loss from continuing operations for the second quarter of 2009 was $2.2 million compared to second quarter 2008 income from continuing operations of $83.2 million mainly due to lower commodity prices.

Net Income (Loss). Our net loss in the second quarter of 2009 was $2.3 million compared to second quarter of 2008 net income of $81.9 million.

Results of Continuing Operations — Six months Ended June 30, 2009 and 2008

Revenues. Our revenues in the first six months of 2009 decreased by 65% compared to revenues in the same period in 2008, mainly due to lower commodity prices. Crude oil production was 46% of our production volumes in the first six months of 2009 and 55% of our production in the first six months of 2008. Natural gas production was 41% of our production volumes in the first six months of 2009 and 33% in the first six months of 2008.

Our properties are divided into the following core areas: The Southeast Louisiana core area includes the Lake Washington and Bay de Chene fields. The Central Louisiana/East Texas core area includes the Brookeland, Masters Creek, South Bearhead Creek, and Chunchula fields. The South Louisiana core area includes the Cote Blanche Island, Horseshoe Bayou/Bayou Sale, Jeanerette, High Island, and Bayou Penchant fields. The South Texas core area includes the AWP, Briscoe Ranch, Las Tiendas, and Sun TSH fields.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the six months ended June 30, 2009 and 2008:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (MBoe)	
	2009	2008	2009	2008
S. E. Louisiana	$93.5	$294.0	2,360	2,935
South Texas	37.5	85.7	1,424	1,344
Central Louisiana / E. Texas	16.8	45.7	459	509
South Louisiana	11.1	36.0	363	449
Strategic Growth	0.3	1.8	16	27
Total	$159.2	$463.2	4,622	5,264

Oil and gas sales for the first six months of 2009 decreased by 66%, or $304.0 million, from the level of those revenues for the comparable 2008 period, and our net sales volumes in the first six months of 2009 decreased by 12%, or 0.6 MMBoe, over net sales volumes in the first six months of 2008. Average prices for oil decreased to $48.01 per Bbl in the first six months of 2009 from $112.59 per Bbl in the first six months of 2008. Average natural gas prices decreased to $3.66 per Mcf in the first six months of 2009 from $9.29 per Mcf in the first six months of 2008. Average NGL prices decreased to $25.40 per Bbl in the first six months of 2009 from $63.60 per Bbl in the first six months of 2008.

In the first six months of 2009, our $304.0 million decrease in oil, NGL, and natural gas sales, compared to the first six months a year earlier, resulted from:

- Price variances that had a $224.7 million unfavorable impact on sales, of which $137.9 million was attributable to the 57% decrease in average oil prices received, $23.5 million was attributable to the 60% decrease in NGL prices, and $63.3 million was attributable to the 61% decrease in natural gas prices; and
- Volume variances that had a $79.3 million unfavorable impact on sales, with $86.3 million of decreases attributable to the 0.8 million Bbl decrease in oil sales volumes, partially offset by a $0.6 million increase due to the less than 0.1 million Bbl increase in NGL sales volumes, and a $6.4 million increase due to the 0.7 Bcf increase in natural gas sales volumes.

The following table provides additional information regarding our first six months of 2009 and 2008 oil and gas sales from continuing operations excluding any effects of our hedging activities:

	Sales Volume				Average Sales Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural gas (Mcf)
Six months Ended June 30, 2009	2,135	615	11.2	4,622	$48.01	$25.40	$3.66
Six months Ended June 30, 2008	2,901	606	10.5	5,264	$112.59	$63.60	$9.29

During the first six months of 2009 and 2008, we recognized net losses of less than $0.1 million and $1.9 million, respectively, related to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of operations. Had these losses been recognized in the oil and gas sales account, our average oil sales price would have been the same and $0.23 per barrel lower for the first six months of 2009 and 2008, respectively, and our average natural gas sales price would have been the same and $0.12 per Mcf lower for the first six months of 2009 and 2008, respectively.

Costs and Expenses. Our expenses in the first six months of 2009 increased $1.7 million, or 1%, compared to expenses in the same period of 2008 principally due to a non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and gas properties as a result of lower oil and natural gas prices at the end of the first quarter of 2009.

Our first six months of 2009 general and administrative expenses, net, decreased $4.2 million, or 21%, from the level of such expenses in the same 2008 period. The decrease was primarily due to decreased stock compensation and salaries and burdens related to a reduction in workforce during the first quarter of 2009. For the first six months of 2009 and 2008, our capitalized general and administrative costs totaled $12.1 million and $14.7 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.46 per Boe in the first six months of 2009 from $3.84 per Boe in the first six months of 2008. The portion of supervision fees recorded as a reduction to general and administrative expenses was $5.7 million and $7.8 million for six month periods ended June 30, 2009 and 2008, respectively.

DD&A decreased $25.5 million, or 23%, in the first six months of 2009 from levels in the first six months of 2008. The decrease is mainly due to decreases in the depletable oil and gas property base due to the non-cash write-down of oil and gas properties in the fourth quarter of 2008 and first quarter of 2009, lower production volumes, and lower future development costs, partially offset by a reduction in reserves volumes when compared to the 2008 period. Our DD&A rate per Boe of production was $18.24 and $20.85 in the first six months of 2009 and 2008, respectively.

We recorded $1.4 million and $0.9 million of accretions to our asset retirement obligation in the first six months of 2009 and 2008, respectively.

Our lease operating costs decreased $16.4 million, or 30%, from the level of such expenses in the same 2008 period. Lease operating costs decreased during 2009 due to decreased workover costs, lower natural gas and NGL processing costs, and lower plant operating costs in 2009 resulting from targeted cost reduction initiatives. Our lease operating costs per Boe produced were $8.36 and $10.45 in the first six months of 2009 and 2008, respectively.

Severance and other taxes decreased $30.4 million, or 62%, from levels in the first six months of 2008. The decrease in the 2009 period was due primarily to decreased oil and gas revenues that resulted from lower commodity prices. Severance and other taxes as a percentage of oil and gas sales were approximately 11.7% and 10.6% in the first six months of 2009 and 2008, respectively. The percentage increase was due to an increase in the severance tax rate of Louisiana gas production, partially offset by a shift in the production mix from South Louisiana, which has a 12.5% oil severance tax rate.

Our total interest cost in the first six months of 2009 was $18.3 million, of which $3.0 million was capitalized. Our total interest cost in the first six months of 2008 was $20.8 million, of which $3.9 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense was primarily due to lower interest rates on our line of credit, partially offset by increased borrowings against our line of credit facility during the 2009 period.

Our overall effective tax rate was 35.1% and 36.6% for the first six months of 2009 and 2008. The effective tax rate for the first six months of 2009 was lower due to the effect of non deductible expenses, and for the second quarter of 2008 was higher than the U.S. federal statutory rate of 35% primarily because of state income taxes and non deductible expenses. Non deductible expenses increase the effective tax rate when income is positive and lower the effective tax rate in a loss period.

Income (Loss) from Continuing Operations. Our loss from continuing operations for the first six months of 2009 was \$61.2 million compared to the first six months of 2008 income from continuing operations of \$133.1 million due to lower commodity prices and a non-cash write-down of oil and gas properties in the first quarter of 2009.

Net Income (Loss). Our net loss in the first six months of 2009 was \$61.4 million compared to our first six months of 2008 net income of \$130.3 million.

Liquidity and Capital Resources

Recent extreme volatility in worldwide credit and financial markets, combined with rapidly falling prices for oil and natural gas, all of which began in the third quarter of 2008, will continue to have a significant impact on our cash flow, capital expenditures, and liquidity in future periods. See "Overview – Financial Condition."

Net Cash Provided by Operating Activities. For the first six months of 2009, our net cash provided by operating activities from continuing operations was \$83.6 million, representing a 72% decrease as compared to \$294.7 million generated during the first six months of 2008. The \$211.2 million decrease was primarily due to a decrease of \$304.0 million in oil and gas sales, attributable to lower commodity prices and lower oil production, slightly offset by lower expenses.

Accounts Receivable. We assess the collectability of accounts receivable, and, based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both June 30, 2009 and December 31, 2008 we had an allowance for doubtful accounts of less than \$0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Existing Credit Facility. We had borrowings of \$228.0 million under our bank credit facility at June 30, 2009, and \$180.7 million in borrowings at December 31, 2008. Our bank credit facility at June 30, 2009 consisted of a \$500.0 million credit facility with a syndicate of ten banks, and expires in October 2011. In May 2009, in conjunction with the normal semi-annual review, our borrowing base and commitment amount were set at \$300.0 million. This was a decrease from the previous borrowing base of \$400.0 million and commitment amount of \$350.0 million but still in line with our 2009 cash needs. Effective May 1, 2009, the interest rate is either (a) the lead bank's prime rate plus applicable margin or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margins have increased to escalating rates of 100 to 250 basis points above the lead bank's prime rate and escalating rates of 200 to 350 basis points for LIBOR rate loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At June 30, 2009, the lead bank's prime rate was 3.25%.

Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement and expect to remain in compliance with these provisions in 2009 and future periods. Our available borrowings under our line of credit facility provide us liquidity.

In light of recent credit market volatility, many financial institutions have experienced liquidity issues, and governments have intervened in these markets to create liquidity. We have reviewed the creditworthiness of the banks that fund our credit facility. However, if the current credit market volatility is prolonged, future extensions of our credit facility may contain terms and interest rates not as favorable as those of our current credit facility. The next scheduled borrowing base review is November 2009, and it is possible the borrowing base and commitment amounts could be reduced due to lower oil and gas prices and the then current state of the financial and credit markets.

Debt Maturities. Our credit facility, with a balance of $228.0 million at June 30, 2009, extends until October 3, 2011. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $250.0 million of 7-1/8% senior notes mature June 1, 2017.

Working Capital. Our working capital improved from a deficit of $75.4 million at December 31, 2008, to a deficit of $9.0 million at June 30, 2009. The improvement resulted primarily from a decrease in accounts payable and accrued capital costs as the amount spent on capital activities has decreased when compared to prior year levels.

Cash Used in Investing Activities. In the first six months of 2009 our oil and gas property additions were $135.8 million. This amount decreased by $183.2 million, as compared to additions in the first six months of 2008, primarily due to a decrease in our spending on drilling and development, predominantly in our Southeast Louisiana and South Texas core areas. These cash based amounts were significantly higher than accrual based capital expenditures as we paid significant accounts payable and accrued capital cost balances incurred prior to year-end 2008. These 2009 expenditures were funded by $83.6 million of cash provided by operating activities from continuing operations, cash proceeds from our remaining cash balance previously held in New Zealand of $5.0 million and $47.3 million in proceeds from our line of credit borrowings.

We drilled four wells during the first six months of 2009. One development well was completed in the Southeast Louisiana core area, while one development well was unsuccessful in that area. Two development wells were drilled in the South Texas core area and will be completed when natural gas prices are more favorable.

Discontinued Operations

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the condensed consolidated statements of operations and cash flows and the assets and associated liabilities have been classified as held for sale in the condensed consolidated balance sheets. In June 2008, Swift Energy completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received six months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending final resolution of this litigation.

In February 2009, the first $5.0 million payment from the sale of our last permit was released to our attorneys who were holding these proceeds in trust for Swift Energy. In April 2009, after an injunction limiting our ability to use such funds was dismissed in favor of Swift Energy, the proceeds were transferred to our bank account in the United States.

In accordance with SFAS No. 144, “Accounting for the Impairment or Disposal of Long-lived Assets” (“SFAS 144”), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the condensed consolidated balance sheets. During the first half of 2008, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement in place at that time and recorded a non-cash asset write-down of $3.3 million related to these assets. This write-down is recorded in “Loss from discontinued operations, net of taxes” on the accompanying condensed consolidated statements of operations.

The following table summarizes the amounts included in income (loss) from discontinued operations for all periods presented. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported in discontinued operations (in thousands except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Oil and gas sales	$---	$6,370	$---	$14,675
Other revenues	(1)	207	20	781
Total revenues	$(1)	6,577	$20	15,456
Depreciation, depletion, and amortization	---	2,289	---	4,909
Other operating expenses	127	4,241	203	10,136
Non-cash write-down of property and equipment	---	1,200	---	3,296
Total expenses	$127	7,730	$203	18,341
Loss from discontinued operations before income taxes	(128)	(1,153)	(183)	(2,885)
Income tax expense (benefit)	(71)	173	---	(85)
Loss from discontinued operations, net of taxes	$(57)	$(1,326)	$(183)	$(2,800)
Loss per common share from discontinued operations, net of taxes-diluted	$(0.00)	$(0.04)	$(0.01)	$(0.09)
Cash flow provided by operating activities	$(93)	$3,868	$(337)	$6,690
Capital expenditures	$---	$990	$---	$2,013

Share-Based Compensation

We follow SFAS No. 123R, “Share-Based Payment” to account for share-based compensation. We continue to use the Black-Scholes-Merton option pricing model to estimate the fair value of stock-option awards with the following weighted-average assumptions for the indicated periods. No stock options were issued in the second quarter of 2009:

	Three Months Ended June 30,		Six Month Ended June 30,	
	2009	2008	2009	2008
Dividend yield	N/A	0%	0%	0%
Expected volatility	N/A	38.4%	50.5%	38.9%
Risk-free interest rate	N/A	2.5%	1.8%	2.5%
Expected life of options (in years)	N/A	2.0	4.5	4.2
Weighted-average grant-date fair value	N/A	$13.89	$ 6.32	$15.53

The expected term for grants issued during or after 2008 has been based on an analysis of historical employee exercise behavior and has considered all relevant factors including expected future employee exercise behavior. The expected term for grants issued prior to 2008 was calculated using the Securities and Exchange Commission Staff’s shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility, and based on an analysis of all relevant factors, we have used a 5.5 year look-back period to estimate expected volatility of our 2008 and 2009 stock option grants, which is an increase from the four-year period used to estimate expected volatility for grants prior to 2008.

At June 30, 2009, we had $2.2 million and $9.8 million of unrecognized compensation cost related to stock options and restricted stock awards, which is expected to be recognized over a weighted-average period of 1.3 years and 2.0 years, respectively. The compensation expense for restricted stock awards was determined based on the market price of our stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2008 amounts referenced under “Contractual Commitments and Obligations” in Management’s Discussion and Analysis” in our Annual Report on form 10-K for the period ending December 31, 2008.

As of June 30, 2009 we had no off-balance sheet arrangements requiring disclosure pursuant to Item 303(a) of Regulation S-K.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and over the last year that volatility has increased to extreme levels, and low prices are expected to continue for 2009 and possibly future periods. The price of oil began to decline in the third quarter of 2008; price declines accelerated in the fourth quarter of 2008 and first quarter of 2009, however, oil prices made some improvement in the second quarter of 2009. Factors such as worldwide economic conditions and credit availability, worldwide supply disruptions, weather conditions, fluctuating currency exchange rates, and political conditions in major oil producing regions, especially the Middle East, can cause fluctuations in the price of oil. Domestic natural gas prices remained high during much of 2008 when compared to longer-term historical prices but began falling in the third quarter of 2008 and continued to fall into the second quarter of 2009. North American weather conditions, the industrial and consumer demand for natural gas, economic conditions and credit availability, storage levels of natural gas, the level of liquefied natural gas imports, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Income Taxes

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ. Under SFAS No. 109, “Accounting for Income Taxes,” deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. In the 4th quarter of 2008 we recorded additional tax expense and increased other long-term liabilities by $0.3 million, which increased our total balance of our unrecognized tax benefits to $1.3 million. If recognized, these tax benefits would fully impact our effective tax rate.

We do not believe the total of unrecognized tax benefits will significantly increase or decrease during the next 12 months.

Critical Accounting Policies and New Accounting Pronouncements

Property and Equipment. We follow the “full-cost” method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. This calculation is done on a country-by-country basis.

The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of unproved properties. For both reserves estimates (see discussion below) and the impairment of unproved properties (see discussion above), these processes are subjective, and results may change over time based on current information and industry conditions. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

Reserves Estimation. Uncertainties in this calculation stem from the estimating process related to quantities of proved oil and natural gas reserves and the present value of estimated future net cash flows. Proved reserves are quantities of hydrocarbons to be recovered in the future from underground oil and natural gas accumulations that cannot be directly measured in an exact way. Therefore, reserve estimates are made from gathered data of imperfect accuracy and are subject to the same uncertainties inherent in that data. Accordingly, reserves estimates may be different from the quantities of oil and natural gas ultimately recovered.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at June 30, 2009 consisted of floors with strike prices lower than the period-end price and did not materially affect this calculation.

We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. See the discussion above related to reserves estimation.

In the first quarter of 2009, as a result of lower oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and gas properties. In the fourth quarter of 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million ($473.1 million after tax) on our oil and gas properties due to lower oil and natural gas prices at the end of 2008.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near-term. If oil and natural gas prices continue to decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that additional non-cash write-downs of oil and natural gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, additional non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur."

New Accounting Pronouncements. In February 2008, the FASB delayed the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. This standard was adopted on January 1, 2009. The adoption of this statement did not have a material impact on our financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 changes the disclosure requirements for derivative instruments and hedging activities. This statement requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Since this statement only impacts disclosure requirements, the adoption of this statement did not have an impact on our financial position or results of operations.

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 "Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities," ("FSP EITF 03-6-1"). Under the FSP, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. This standard was adopted on January 1, 2009. The adoption of this statement did not have a material impact on our financial position, results of operations, or earnings per share.

In December 2008, the SEC issued release 33-8995, Modernization of Oil and Gas Reporting. This release changes the accounting and disclosure requirements surrounding oil and natural gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The most significant changes include:

- Changes to prices used in reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
- Disclosure of probable and possible reserves are allowed.
- The estimation of reserves will allow the use of reliable technology that was not previously recognized by the SEC.
- Numerous changes in reserves disclosures mandated by SEC Form 10K.

This release is effective for financial statements issued for fiscal years and interim periods beginning on or after January 1, 2010.

In May 2009, the FASB issued SFAS No. 165, "Subsequent Events." SFAS No. 165 that establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We adopted SFAS No 165 for the period ending June 30, 2009, however the adoption of this statement did not have an impact on our financial position or results of operations.

Forward-Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, cash flows, available borrowing capacity, liquidity, acquisition plans, regulatory matters, and competition. Such forward-looking statements generally are accompanied by words such as "plan," "future," "estimate," "expect," "budget," "predict," "anticipate," "projected," "believe," or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and, therefore, actual results may differ materially from those projected. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices; availability of services and supplies; disruption of operations and damages due to hurricanes or tropical storms; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for and availability of capital; conditions in the financial and credit markets; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed in this report and set forth from time to time in our other public reports, filings, and public statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Significant declines in oil and natural gas prices began in the last half of 2008, and such pricing volatility has continued in 2009.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- Price Floors – At June 30, 2009 we had in place price floors in effect through the September 2009 contract month for crude oil. The oil price floors cover notional volumes of 645,000 barrels, with a weighted average floor price of $62.00 per barrel. These floors are expected to cover approximately 69% to 73% of our oil production during the third quarter of 2009. The fair value of these instruments at June 30, 2009 was $0.9 million and is recognized on the accompanying balance sheet in "Other current assets." There are no additional cash outflows for these price floors, as the cash premium was paid at inception of the hedge. The maximum loss that could be recognized on our statement of operations from these price floors when they settle during the third quarter of 2009 would be $1.3 million, which represents the original amount paid for these price floors less ineffectiveness previously recognized.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers from certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Interest Rate Risk. Our senior notes and senior subordinated notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At June 30, 2009, we had borrowings of $228.0 million under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 33 basis points and would not have a material adverse effect on our 2009 cash flows based on this same level of borrowing.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including our chief executive officer and our chief financial officer, to allow timely decisions regarding such required disclosure. The Company's chief executive officer and chief financial officer have evaluated such disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first six months of 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

SWIFT ENERGY COMPANY

PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

No material legal proceedings are pending other than ordinary, routine litigation incidental to the Company's business.

Item 1A. Risk Factors.

Climate change legislation and regulatory initiatives could result in increased compliance costs and affect demand for the oil and natural gas we produce.

There has been recent debate that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere along with other factors. In response to this debate, the U.S. Congress is currently considering legislation that would restrict the emission of greenhouse gases, with the House of Representatives having passed a bill on June 26, 2009 that would impose a national cap on emissions of greenhouse gases that would require major sources of greenhouse gases to obtain "allowances" that would permit such sources to continue to emit greenhouse gases into the atmosphere. Unrelated to this activity in Congress, the U.S. Environmental Protection Agency or "EPA" issued a notice on April 17, 2009 of its proposed findings and determination that emission of greenhouse gases presented an endangerment to human health and the environment. If finalized, EPA's finding and determination would allow it to begin regulating emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Through a separate action, the EPA is considering whether it will regulate greenhouse gases as "air pollutants" under the existing federal Clean Air Act. In addition, more than one-third of the states (but not currently including Louisiana or Texas) either individually or through multi-state initiatives already have begun implementing legal measures to reduce emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an effect on demand for the oil and natural gas we produce.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

The following table summarizes repurchases of our common stock occurring during the second quarter of 2009:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
04/01/09 – 04/30/09 (1)	767	$10.61	---	$---
	692	13.63	---	---

05/01/09 – 05/31/09 (1)				
06/01/09 – 06/30/09 (1)	396	16.43	---	---
Total	1,855	$12.98	---	$---

(1) These shares were withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

Our annual meeting of shareholders was held on May 12, 2009. At the record date, 31,160,232 shares of common stock were outstanding and entitled to one vote per share upon all matters submitted at the meeting. At the annual meeting, Clyde W. Smith, Terry E. Swift, and Charles J. Swindells were elected to serve as directors of Swift Energy for three-year terms to expire at the 2011 annual meeting of shareholders. These directors were elected by the following votes:

Nominees for Director	For	Withheld
Clyde W. Smith, Jr.	13,921,900	14,411,176
Terry E. Swift	19,847,561	8,485,516
Charles J. Swindells	13,910,293	14,422,783

The following proposals were also approved at the annual meeting:

Proposal	For	Against	Abstain	Broker Non-Vote
Proposal to amend the Company's First Amended and Restated 2005 Stock Compensation Plan	19,519,184	4,870,041	175,424	3,768,427
Company's Independent Auditor for the fiscal year ending December 31, 2009	27,991,480	206,700	134,896	0

Item 5. Other Information.

None.

Item 6. Exhibits.

10.1 Amendment No. 1 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan, effective as of April 1, 2009 (incorporated by reference as Exhibit 10 to the Swift Energy Company Form 8-K filed April 7, 2009).

10.2 Amendment No. 2 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan, effective as of May 12, 2009 (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Form 8-K filed May 14, 2009).

31.1* Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32*

Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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.

SWIFT ENERGY COMPANY
(Registrant)

Date: August 3, 2009	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: August 3, 2009	By:	/s/ David W. Wesson. David W. Wesson Controller and Principal Accounting Officer

Exhibit Index

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* Filed herewith