SWIFT ENERGY CO
Form 10-Q
May 07, 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 March 31, 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.
YesþNo 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).
YesoNo 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 accelerated filer	þ	Accelerated filer	o	Non-accelerated filer	o	Smaller reporting company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes o No 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) (Class of Stock)	31,163,715 Shares (Outstanding at April 30, 2009)

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SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2009
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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	March 31, 2009 (Unaudited)	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,534	$ 283
Accounts receivable-		
Oil and gas sales	36,082	37,364
Joint interest owners	2,869	4,235
Other Receivables	12,396	20,065
Other current assets	26.886	15,575
Current assets held for sale	564	564
Total Current Assets	82,331	78,086
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	3,313,703	3,270,159
Unproved properties	95,032	91,252
	3,408,735	3,361,411
Furniture, fixtures, and other equipment	38,010	37,669
	3,446,745	3,399,080
Less – Accumulated depreciation, depletion, and amortization	(2,091,388)	(1,967,633)
	1,355,357	1,431,447
Other Assets:		
Debt issuance costs	5,809	6,107
Restricted assets	1,649	1,648
	7,458	7,755
	$ 1,445,146	$ 1,517,288
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 53,852	$ 66,802
Accrued capital costs	48,397	74,315
Accrued interest	8,725	7,207
Undistributed oil and gas revenues	5,273	5,175
Total Current Liabilities	116,247	153,499
Long-Term Debt	636,700	580,700
Deferred Income Taxes	99,507	130,899
Asset Retirement Obligation	46,056	48,785
Other Long-Term Liabilities	2,469	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, 31,576,526 and 31,336,472 shares issued, and 31,160,427 and 30,868,588 shares outstanding, respectively	316	313
Additional paid-in capital	436,262	435,307
Treasury stock held, at cost, 416,099 and 467,884 shares, respectively	(8,970)	(10,431)
Retained earnings	116,559	175,688
	544,167	600,877
	$ 1,445,146	$ 1,517,288

See accompanying Notes to Consolidated Financial Statements.

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Revenues:		
Oil and gas sales	$ 76,418	$ 199,973
Price-risk management and other, net	(59)	(1,013)
	76,359	198,960
Costs and Expenses:		
General and administrative, net	8,419	9,919
Depreciation, depletion, and amortization	43,934	52,494
Accretion of asset retirement obligation	702	454
Lease operating cost	19,808	26,425
Severance and other taxes	8,686	22,136
Interest expense, net	7,467	8,690
Write-down of oil and gas properties	79,312	---
	168,328	120,118
Income (Loss) from Continuing Operations Before Income Taxes	(91,969)	78,842
Provision for Income Taxes (Benefit)	(32,966)	29,007
Income (Loss) from Continuing Operations	(59,003)	49,835
Loss from Discontinued Operations, net of taxes	(126)	(1,474)
Net Income (Loss)	$ (59,129)	$ 48,361
Per Share Amounts-		
Basic: Income (Loss) from Continuing Operations	$ (1.90)	$ 1.61
Loss from Discontinued Operations, net of taxes	(0.00)	(0.05)
Net Income (Loss)	$ (1.91)	$ 1.56
Diluted: Income (Loss) from Continuing Operations	$ (1.90)	$ 1.59
Loss from Discontinued Operations, net of taxes	(0.00)	(0.05)
Net Income (Loss)	$ (1.91)	$ 1.54
Weighted Average Shares Outstanding	31,031	30,347

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 Income (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 loss:						
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
Purchase of treasury shares (42,238 shares) (2)	-	-	(633)	-	-	(633)
Tax benefit shortfall from stock-based awards (2)	-	(1,503)	-	-	-	(1,503)
Employee stock purchase plan (50,690 shares) (2)	1	724	-	-	-	725
Issuance of restricted stock (189,364 shares) (2)	2	(2)	-	-	-	-
Amortization of stock compensation (2)	-	2,452	-	-	-	2,452
Net income (2)	-	-	-	(59,129)	-	(59,129)
Total comprehensive income (2)						(59,129)
Balance, March 31, 2009 (2)	$ 316	$ 436,262	$ (8,970)	$ 116,559	$ -	$ 544,167

(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)	Three Months Ended March 31, 2009	2008
Cash Flows from Operating Activities:		
Net income (loss)	$ (59,129)	$ 48,361
Plus loss from discontinued operations, net of taxes	126	1,474
Adjustments to reconcile net income (loss) to net cash provided by operation activities -		
Depreciation, depletion, and amortization	43,934	52,494
Write-down of oil and gas properties	79,312	---
Accretion of asset retirement obligation	702	454
Deferred income taxes	(29,866)	28,428
Stock-based compensation expense	2,029	2,632
Other	9,172	2,409
Change in assets and liabilities-		
Decrease in accounts receivable	2,648	2,272
Increase (decrease) in accounts payable and accrued liabilities	536	(950)
Increase (decrease) in income taxes payable	(248)	579
Increase in accrued interest	1,518	1,537
Cash Provided by operating activities – continuing operations	50,734	139,690
Cash Provided by (Used in) operating activities – discontinued operations	(244)	2,822
Net Cash Provided by Operating Activities	50,490	142,512
Cash Flows from Investing Activities:		
Additions to property and equipment	(103,370)	(176,402)
Proceeds from the sale of property and equipment	40	79
Cash Used in investing activities – continuing operations	(103,330)	(176,323)
Cash Used in investing activities – discontinued operations	---	(1,023)
Net Cash Used in Investing Activities	(103,330)	(177,346)
Cash Flows from Financing Activities:		
Net proceeds from bank borrowings	56,000	36,400
Net proceeds from issuances of common stock	724	3,887
Excess tax benefits from stock-based awards	---	467
Purchase of treasury shares	(633)	(1,387)
Cash provided by financing activities – continuing operations	56,091	39,367
Cash provided by financing activities – discontinued operations	---	---
Net Cash Provided by financing activities	56,091	39,367
Net Increase in Cash and Cash Equivalents	$ 3,251	$ 4,533
Cash and Cash Equivalents at Beginning of Period	283	5,623
Cash and Cash Equivalents at End of Period	$ 3,534	$ 10,156
Supplemental Disclosures of Cash Flows Information:		

Cash paid during period for interest, net of amounts capitalized	$	5,652	$	6,872
Cash paid during period for income taxes	$	---	$	---

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.

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.

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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 quarters ended March 31, 2009 and 2008, such internal costs capitalized totaled $6.3 million and $6.8 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the quarters ended March 31, 2009 and 2008, capitalized interest on unproved properties totaled $1.5 million and $2.0 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, recorded at cost, 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"). We did not have any outstanding derivative instruments at March 31, 2009 that would affect this calculation.

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 March 31, 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.

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 March 31, 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, and still have additional claims outstanding. We expect the remainder of costs for the replacement of assets related to Hurricanes Gustav and Ike, primarily in the Bay de Chene field, will be incurred in the second 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 income statements 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 first quarter of 2008, we recognized a net loss of $1.0 million relating to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of income. 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. The ineffectiveness reported in “Price-risk management and other, net” for the first quarter of 2008 was not material.

At March 31, 2009, we did not have any outstanding derivative instruments in place for future production.

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 income (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 income (loss), net of income tax” and recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of income. The fair value of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers.

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 three 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 $2.8 million and $3.9 million in the first three 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 $19.5 million at March 31, 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 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.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of March 31, 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 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 March 31, 2009 and December 31, 2008 are liabilities of approximately $3.8 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 Income (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 March 31, 2009 and December 31, 2008, we recorded no derivative gains or losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet.

Total comprehensive loss for the first quarter of 2009 was $59.1 million, while total comprehensive income was $48.3 million for the first quarter of 2008.

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 three months ended March 31	702	454
Liabilities incurred for wells, facilities construction, and site restoration	3,234	227
Liabilities incurred for acquisitions	---	---
Reductions due to sold, or plugged and abandoned wells	(302)	(25)
Revisions in estimated cash flows	---	---
Asset Retirement Obligation as of March 31	$ 52,419	$ 35,115

At March 31, 2009 and December 31, 2008, approximately $6.4 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 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 the PV-10 and volumetric 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 applies to annual reports on Form 10-K for fiscal years ending on or after December 31, 2009.

(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. These benefits were $1.4 million for the three months ended March 31, 2008. The benefit for the first quarter of 2008 that was not recognized in the financial statements as these benefits had not been realized due to a tax net operating loss position for the quarter was $0.9 million. For the three months ended March 31, 2009, we recognized a tax benefit shortfall of $1.5 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.

Net cash proceeds from the exercise of stock options were $2.9 million for the three months ended March 31, 2008. The actual income tax benefit realized from stock option exercises was $1.5 million for the three months ended March 31, 2008. No stock options were exercised during the three months ended March 31, 2009.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees was recorded in "General and administrative, net" in the accompanying condensed consolidated statements of income, and was $1.8 million and $2.4 million for the quarters ended March 31, 2009 and 2008, respectively, and stock compensation recorded in lease operating cost was $0.1 million and $0.2 million for the quarters ended March 31, 2009 and 2008, respectively. We also capitalized $0.4 million and $1.1 million of stock compensation in the first quarters of 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:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Dividend yield	0%	0%
Expected volatility	50.5%	39.0%
Risk-free interest rate	1.8%	2.5%
Expected life of options (in years)	4.5	4.8
Weighted-average grant-date fair value	$ 6.32	$ 15.96

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 March 31, 2009, there was $2.8 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 three months ended March 31, 2009:

	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	1,119,469	$ 33.22
Options granted	273,400	$ 14.66
Options canceled	(34,057)	$ 40.63
Options exercised	---	$ ---
Options outstanding, end of period	1,358,812	$ 29.18
Options exercisable, end of period	764,445	$ 28.78

As all of our outstanding stock options at March 31, 2009 have exercise prices higher than the quarter-end stock price, the options outstanding and exercisable at March 31, 2009 have no intrinsic value and have a weighted average remaining contract life of 5.9 years and 4.1 years, respectively. No stock options were exercised during the three months ended March 31, 2009.

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 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 March 31, 2009, we had unrecognized compensation expense of approximately $9.1 million associated with these awards which are expected to be recognized over a weighted-average period of 1.9 years. The grant date fair value of shares vested during the three months ended March 31, 2009 was $8.0 million.

The following table represents restricted stock activity for the three months ended March 31, 2009:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	586,325	$ 42.78
Restricted shares granted	190,000	$ 14.66
Restricted shares canceled	(44,045)	$ 43.02
Restricted shares vested	(189,551)	$ 42.33
Restricted shares outstanding, end of period	542,729	$ 33.08

(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 first quarter 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 periods ended March 31, 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 periods ended March 31, 2009 and 2008 (in thousands, except per share amounts):

	2009			2008		
	Income 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	$ (59,003)	31,031		$ 49,835	30,347	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	---	---		$ (1,070)	---	
Income (Loss) from continuing operations allocated to common shares	$ (59,003)	31,031	$ (1.90)	$ 48,765	30,347	$ 1.61
Dilutive Securities:						
Plus: Income (Loss) from continuing operations allocated to unvested shareholders	---	---		$ 1,070	---	
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders	---	---		$ (1,056)	---	
Stock Options	---	---		---	400	
Diluted EPS:						
Income (Loss) from continuing operations allocated to common shares, and assumed Share conversions	$ (59,003)	31,031	$ (1.90)	$ 48,779	30,747	$ 1.59

The adoption of FSP EITF 03-6-1 lowered our first quarter 2008 Basic EPS and Diluted EPS for continuing operations by $0.03 per share and $0.02 per share, respectively, from previously reported amounts. Options to purchase approximately 1.4 million shares at an average exercise price of $29.18 were outstanding at March 31, 2009, while options to purchase 1.4 million shares at an average exercise price of $31.17 were outstanding at March 31, 2008. All of the 1.4 million stock options to purchase shares outstanding at March 31, 2009 were not included in the computation Diluted EPS for the three months ended March 31, 2009, as they would be antidilutive given the net loss from continuing operations. Approximately 1.0 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months 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 $0.09

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 March 31, 2009 and December 31, 2008, was as follows (in thousands):

	March 31, 2009	December 31, 2008
Bank Borrowings	$ 236,700	$ 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	$ 636,700	$ 580,700

Bank Borrowings. At March 31, 2009, we had borrowings of $236.7 million under our $500.0 million credit facility with a syndicate of ten banks, which is based entirely on assets from continuing operations 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 March 31, 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 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 $1.4 million and $2.9 million for the first quarters of 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 March 31, 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 in twelve-month intervals 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 condensed 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 both the three months ended March 31, 2009 and 2008, respectively.

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 the three months ended March 31, 2009 and 2008.

The maturities on our long-term debt are $0 for 2009 and 2010, $386.7 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 March 31, 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 income 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 the outcome 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 at March 31, 2009. In April 2009, after an injunction limiting our ability to use such funds was dismissed in favor of Swift, the proceeds were transferred to Swift. As of March 31, 2009, pending the outcome of the permit litigation mentioned above, we have recorded $5.0 million to “Other Receivables” and a corresponding amount related to deferred revenue in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated financial statements.

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 quarter 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 $2.1 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 income.

The book value of our remaining New Zealand permit is approximately $0.6 million at March 31, 2009.

The following table summarizes the amounts included in "Income (Loss) from Discontinued Operations, net of taxes" for all periods presented (in thousands except per share amounts):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Oil and gas sales	$ ---	$ 8,305
Other revenues	21	574
Total revenues	$ 21	8,879
Depreciation, depletion, and amortization	---	2,620
Other operating expenses	76	5,895
Non-cash write-down of property and equipment	---	2,096
Total expenses	$ 76	10,611
Loss from discontinued operations before income taxes	(55)	(1,732)
Income tax expense (benefit)	71	(258)
Loss from discontinued operations, net of taxes	$ (126)	$ (1,474)
Loss per common share from discontinued operations-diluted	$ (0.00)	$ (0.05)
Sales volumes (MBoe)	---	248
Cash flow provided by (used in) operating activities	$ (244)	$ 2,822
Capital expenditures	$ ---	$ 1,023

(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.

As of March 31, 2009, we did not have any assets that are measured at fair value in accordance with SFAS No. 157, “Fair Value Measurements.”

(9) Condensed Consolidating 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:

Condensed Consolidating Balance Sheets

(in thousands)	March 31, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 76,707	$ 5,624	$ ---	$ 82,331
Property and equipment	---	1,355,357	---	---	1,355,357
Investment in subsidiaries (equity method)	544,167	---	472,623	(1,016,790)	---
Other assets	---	7,458	70,992	(70,992)	7,458
Total assets	$ 544,167	$ 1,439,522	$ 549,239	$ (1,087,782)	$ 1,445,146
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 111,175	$ 5,072	$ ---	$ 116,247
Long-term liabilities	---	855,724	---	(70,992)	784,732
Stockholders' equity	544,167	472,623	544,167	(1,016,790)	544,167
Total liabilities and stockholders' equity	$ 544,167	$ 1,439,522	$ 549,239	$ (1,087,782)	$ 1,445,146

(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

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Condensed Consolidating Statements of Income

(in thousands)	Three Months Ended March 31, 2009				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 76,359	$ ---	$ ---	$ 76,359
Expenses	---	168,328	---	---	168,328
Income (Loss) before the following:	---	(91,969)	---	---	(91,969)
Equity in net earnings of subsidiaries	(59,129)	---	(59,003)	118,132	---
Income (Loss) from continuing operations, before income taxes	(59,129)	(91,969)	(59,003)	118,132	(91,969)
Income tax provision (Benefit)	---	(32,966)	---	---	(32,966)
Income (Loss) from continuing operations	(59,129)	(59,003)	(59,003)	118,132	(59,003)
Loss from discontinued operations, net of taxes	---	---	(126)	---	(126)
Net income (Loss)	$ (59,129)	$ (59,003)	$ (59,129)	$ 118,132	$ (59,129)

(in thousands)	Three Months Ended March 31, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 198,960	$ ---	$ ---	$ 198,960
Expenses	---	120,118	---	---	120,118
Income (Loss) before the following:	---	78,842	---	---	78,842
Equity in net earnings of subsidiaries	48,361	---	49,835	(98,196)	---
Income (Loss) from continuing operations, before income taxes	48,361	78,842	49,835	(98,196)	78,842
Income tax provision (Benefit)	---	29,007	---	---	29,007
Income (Loss) from continuing operations	48,361	49,835	49,835	(98,196)	49,835
Loss from discontinued operations, net of taxes	---	---	(1,474)	---	(1,474)
Net income (Loss)	$ 48,361	$ 49,835	$ 48,361	$ (98,196)	$ 48,361

Condensed Consolidating Statements of Cash Flow

(in thousands)	Three Months Ended March 31, 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	$ ---	$ 50,734	$ (244)	$ ---	$ 50,490
Cash flow from investing activities	---	(103,438)	---	108	(103,330)
Cash flow from financing activities	---	56,091	108	(108)	56,091
Net increase (decrease) in cash	---	3,387	(136)	---	3,251
Cash, beginning of period	---	87	196	---	283
Cash, end of period	$ ---	$ 3,474	$ 60	$ ---	$ 3,534

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(in thousands)	Three Months Ended March 31, 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	$ ---	$ 139,690	$ 2,822	$ ---	$ 142,512
Cash flow from investing activities	---	(176,080)	(1,023)	(243)	(177,346)
Cash flow from financing activities	---	39,367	(243)	243	39,367
Net increase in cash	---	2,977	1,556	---	4,533
Cash, beginning of period	---	180	5,443	---	5,623
Cash, end of period	$ ---	$ 3,157	$ 6,999	$ ---	$ 10,156

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

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 32 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 the largest producer of crude oil in the state of Louisiana, and due to increasing emphasis on our South Louisiana operations, oil constitutes 47% of our first quarter of 2009 production, and together with our natural gas liquids ("NGLs") production makes up 60% of our total production for the first quarter. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in the first 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.

First Quarter 2009 Oil and Natural Gas Pricing

Recent extreme volatility in worldwide credit and financial markets, combined with rapidly falling 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 six months. Both oil and natural gas prices we received in the first quarter of 2009 were lower than the average prices we received in the fourth quarter of 2008, with a 32% decline in average prices per BOE received from the fourth quarter of 2008 to those received in the first quarter of 2009. These declines reduced our cash flow from operations in the first quarter and will continue to reduce our cash flow from operations in future periods in which prices remain at these lower levels.

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.

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. We have reduced our 2009 capital expenditures budget to a range of $125 million to $150 million, compared to our 2008 total capital costs incurred of $646 million including acquisitions. We have spent $47.7 million in the first quarter of 2009, primarily related to the completion of projects began in 2008. We expect our budgeted capital expenditures to be in line with our expected cash flows from operating activities for 2009.

- Released all drilling rigs in early 2009. We did not spud any wells in 1Q09 and have limited drilling activities in our reduced 2009 capital expenditures budget. We will begin drilling again in the second quarter of 2009 on a limited basis as drilling costs have decreased somewhat and become more in line with the current oil and gas pricing environment.
- Reduced our workforce. In early 2009, we reduced our workforce to lower general and administrative costs in future periods, although the first quarter of 2009 effect was minimal given severance and other associated costs.

- Adjusted operations. We have adjusted our operations and facility usage to levels which will reduce lease operating expense in 2009 and future periods.
- Continued our review of the credit worthiness of customers. Given the downturn in the industry we have examined every one of our purchasers of oil and gas for credit worthiness and we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. We also obtain letters of credit or parent company guaranties from certain customers, if applicable, to reduce risk of loss.
- 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.
  - Reviewed the banks in our line of credit facility. In light of recent credit market volatility, many financial institutions have experienced liquidity issues, and governments have intervened in these markets to create liquidity, and provide capital. We have reviewed the credit worthiness of the banks that fund our credit facility.
- Evaluated our insurers. As part of the renewal process, we and our insurance brokers have evaluated our potential insurers to ensure financial stability and sufficient wherewithal to pay claims.
- Continued to monitor our debt covenants. 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 these agreements and expect to remain in compliance with these provisions in 2009 and future periods.

Financial Condition

Our debt to capitalization ratio increased to 54% at March 31, 2009, as compared to 49% at year-end 2008, as total equity and retained earnings decreased as a result of the first quarter 2009 non-cash write-down of our oil and gas properties. Our debt to PV-10 ratio increased to 50% at March 31, 2009 from 43% at year-end 2008, primarily due to lower period-end prices used in the reserves calculation.

Operating Results

In our first quarter 2009 continuing operations we had revenues of $76.4 million, a decrease of 62% over comparable 2008 levels. Our weighted average sales price received decreased 58% to $32.29 per Boe for the first quarter of 2009 from $77.80 per Boe in the 2008 period. Our $122.6 million decrease in revenues resulted from lower oil, natural gas, and NGL prices during the first quarter of 2009, along with an 8% decrease in production mainly due to shut-in production at our Bay de Chene field and natural declines in our Lake Washington field.

Our loss from continuing operations for the first quarter of 2009 was $59.0 million compared to income from continuing operations of $49.8 million in the first quarter of 2008. Excluding the first quarter of 2009 non-cash write-down 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.

Our overall costs and expenses increased in the first quarter of 2009 by $48.2 million, when compared to 2008 levels, due to the $79.3 million non-cash write-down of oil and gas properties. Lease operating costs decreased by 25% due to less workover costs, decreased natural gas processing costs, and a decrease in plant operating expense resulting from targeted cost reduction initiatives. Depreciation, depletion and amortization expense decreased 16%, mainly due to our lower depletable property base in the 2009 period as we incurred a significant non-cash write-down of oil and gas properties in the fourth quarter of 2008, 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. Severance and other taxes also decreased 61% mainly due to decreased oil and gas revenues. We expect the market forces that were putting upward pressure on production costs in early 2008 will continue to soften as activity levels decline in response to falling commodity prices and current conditions in the financial markets in 2009. In 2009, we will continue to focus upon our capital efficiency to fully manage our costs and expenses.

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 will also be utilized to process production from our SL 18669 #1 (Shasta) well starting in the second quarter.

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, and still have additional claims outstanding. We expect the remainder of costs for the replacement of assets related to Hurricanes Gustav and Ike, primarily in the Bay de Chene field, will be incurred in the second 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.

Asset Acquisitions

In September 2008, we acquired oil and natural gas interests in South Texas for approximately $45.9 million in cash including purchase price adjustments. The property interests are located in the Briscoe “A” lease in Dimmit County. These properties are now included within our South Texas core area.

Capital Expenditures

Our capital expenditures on a cash flow basis during the first quarter of 2009 were $103.4 million. This amount decreased by $73.0 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 $50.7 million of cash provided by operating activities from continuing operations and $56.0 million in proceeds from our line of credit borrowings. These first quarter 2009 cash based amounts were significantly higher than accrual based capital expenditures of $47.7 million as we reduced our accounts payable and accrued capital cost balances from year-end levels.

Given the current low oil and gas pricing environment, our presently budgeted 2009 capital expenditures range between $125 million to $150 million, net of minor non-core dispositions and excluding any property acquisitions. Based upon current market conditions and our estimates, our capital expenditures for 2009 should be within our anticipated cash flow from operations. 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 year or if strategic opportunities warrant. If 2009 capital expenditures exceed our cash flow from operating activities, we anticipate funding those expenditures with our credit facility.

Our 2009 capital expenditures are expected to include drilling up to three horizontal wells in the Olmos sands in our AWP field, drilling a well in the Eagle Ford shale formation of our AWP field, drilling an exploratory well in our Southeast Louisiana core area along with completing a pipeline from our existing Shasta well to the Westside facility, facility projects in our Bay de Chene field, recompletions in our Southeast Louisiana core area, and fracture enhancements in our South Texas core area. Should commodity prices strengthen, we are prepared to drill up to 10 additional wells to shallow and intermediate depths in our Southeast Louisiana core area.

In the Lake Washington and Bay de Chene fields activities planned for 2009 include continuing to work on our 3D seismic depth migration of the merged data sets with an updated "salt model." We completed a pilot seismic "pore-pressure" prediction project. This has allowed us to increase our confidence level as we begin to drill some of the deeper and higher impact wells in this area of South Louisiana. For example, in late 2008 we successfully completed our Shasta prospect well and hooked it up to facilities in late April 2009. In the first quarter of 2009 we completed drilling one of our West Newport prospects and began production early in the second quarter. A full inventory of deep and higher impact tests have been developed for future drilling. This includes developing and planning a sub-salt exploratory test, which could be drilled next year dependant upon the commodity pricing environment.

Results of Continuing Operations — Three Months Ended March 31, 2009 and 2008

Revenues. Our revenues in the first quarter of 2009 decreased by 62% compared to revenues in the same period in 2008, primarily due to lower commodity prices, along with lower oil and NGL volumes. Revenues for both periods were substantially comprised of oil and gas sales. Crude oil production was 47% of our production volumes in the first quarter of 2009 and 55% of our production in the first quarter of 2008. Natural gas production was 40% of our production volumes in the first quarter of 2009 and 32% in the first 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, Chunchula and Frisco City 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 periods ended March 31, 2009 and 2008:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (MBoe)	
	2009	2008	2009	2008
S. E. Louisiana	$ 42.7	$ 128.7	1,175	1,466
South Texas	18.0	38.4	718	665
Central Louisiana / E. Texas	7.5	19.0	230	239
South Louisiana	6.1	13.3	201	187
Strategic Growth	2.1	0.6	42	13
Total	$ 76.4	$ 200.0	2,366	2,570

Oil and gas sales for the first quarter of 2009 decreased by 62%, or $123.6 million, from the level of those revenues for the comparable 2008 period, and our net sales volumes in the first quarter of 2009 decreased by 8%, or 0.2 MMBoe, compared to net sales volumes in the first quarter of 2008. Average prices for oil decreased to $41.15 per Bbl in the first quarter of 2009 from $99.43 per Bbl in the first quarter of 2008. Average natural gas prices decreased to $4.19 per Mcf in the first quarter of 2009 from $7.97 per Mcf in the first quarter of 2008. Average NGL prices decreased to $22.52 per Bbl in the first quarter of 2009 from $59.80 per Bbl in the first quarter of 2008.

In the first quarter of 2009, our $123.6 million decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $97.6 million unfavorable impact on sales, of which $64.6 million was attributable to the 59% decrease in average oil prices received, $11.4 million was attributable to the 62% decrease in NGL prices, and $21.6 million was attributable to the 47% decrease in natural gas prices; and

- Volume variances that had a $25.9 million unfavorable impact on sales, with $31.0 million of decreases attributable to the 0.3 million Bbl decrease in oil sales volumes and a $0.5 million decrease due to the less than 0.1 million Bbl decrease in NGL sales volumes, partially offset by a $5.6 million increase due to the 0.7 Bcf increase in natural gas 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 March 31, 2009	1,108	307	5.7	2,366	$ 41.15	$ 22.52	$ 4.19
Three Months Ended March 31, 2008	1,420	316	5.0	2,570	$ 99.43	$ 59.80	$ 7.97

During the first quarter of 2009 we had no derivative instruments in place and during the first quarter of 2008 we recorded a net loss of $1.0 million related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. Had this loss been recognized in the oil and gas sales account, our average oil sales price would have been $99.01 for the first quarter of 2008, and our average natural gas sales price would have been $7.88 for the first quarter of 2008.

Costs and Expenses. Our expenses in the first quarter of 2009 increased $48.2 million, or 40%, 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 March 31, 2009.

Our first quarter 2009 general and administrative expenses, net, decreased $1.5 million, or 15%, from the level of such expenses in the same 2008 period. The decrease was primarily due to decreased stock compensation and salaries and burdens, partially offset by an increase in severance costs related to a reduction in workforce during the first quarter of 2009. For the first quarters of 2009 and 2008, our capitalized general and administrative costs totaled $6.3 million and $6.8 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.56 per Boe in the first quarter of 2009 from $3.86 per Boe in the first 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 March 31, 2009 and 2008.

DD&A decreased $8.6 million, or 16%, in the first quarter of 2009, from levels in the first 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, 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 $18.57 and $20.42 in the first quarters of 2009 and 2008.

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

Our lease operating costs decreased $6.6 million, or 25%, compared to the level of such expenses in the same 2008 period. Lease operating costs decreased during 2009 due to lower 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 $8.37 and $10.28 in the first quarters of 2009 and 2008, respectively.

Severance and other taxes decreased $13.5 million, or 61%, from levels in the first quarter of 2008. The decrease in the 2009 period was due primarily to lower revenue as a result of lower commodity prices. Severance and other taxes, excluding ad valorem taxes, as a percentage of oil and gas sales were approximately 8.7% and 9.7% in the first quarters of 2009 and 2008, respectively. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana decreased as a percentage of overall production in the first quarter of 2009 compared to the first quarter of 2008, the overall percentage of severance costs to sales also decreased.

Our total interest cost in the first quarter of 2009 was $9.0 million, of which $1.5 million was capitalized. Our total interest cost in the first quarter of 2008 was $10.7 million, of which $2.0 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the first quarter of 2009 was primarily attributable to a decrease in the LIBOR rate on our line of credit.

Our overall effective tax rate was 35.8% and 36.8% for the first quarters of 2009 and 2008. The effective tax rate for the first quarters of 2009 and 2008 were higher than the U.S. federal statutory rate of 35% primarily because of state income taxes. The first quarter 2009 provision for income taxes includes a $1.1 million valuation allowance for state income tax loss carryforwards.

Income(Loss) from Continuing Operations. Our loss from continuing operations for the first quarter of 2009 of ($59.0) million was 218% lower than first quarter of 2008 income from continuing operations of $49.8 million primarily due to the non-cash write-down of oil and gas properties in the first quarter of 2009.

Net Income (Loss). Our loss in the first quarter of 2009 of ($59.1) million was 222% lower than our first quarter of 2008 net income of $48.4 million, due to the non-cash write-down of oil and gas properties in the first quarter of 2009.

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 income 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 the outcome 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 at March 31, 2009. In April 2009, after an injunction limiting our ability to use such funds was dismissed in favor of Swift, the proceeds were transferred to Swift. As of March 31, 2009, pending the outcome of the permit litigation mentioned above, we have recorded $5.0 million to “Other Receivables” and a corresponding amount related to deferred revenue in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated financial statements.

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 quarter 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 $2.1 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 income.

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 March 31, 2009	Three Months Ended March 31, 2008
Oil and gas sales	$ ---	$ 8,305
Other revenues	21	574
Total revenues	21	8,879
Depreciation, depletion, and amortization	---	2,620
Other operating expenses	76	5,895
Non-cash write-down of property and equipment	---	2,096
Total expenses	$ 76	10,611
Loss from discontinued operations before income taxes	(55)	(1,732)
Income tax expense (benefit)	71	(258)
Loss from discontinued operations, net of taxes	$ (126)	$ (1,474)
Loss per common share from discontinued operations, net of taxes-diluted	$ (0.00)	$ (0.05)
Cash flow provided by (used in) operating activities	$ (244)	$ 2,822
Capital expenditures	$ --	$ 1,023

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:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Dividend yield	0%	0%
Expected volatility	50.5%	39.0%
Risk-free interest rate	1.8%	2.5%
Expected life of options (in years)	4.5	4.8
Weighted-average grant-date fair value	$ 6.32	$ 15.96

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 March 31, 2009, there was $2.8 million of unrecognized compensation cost related to stock options, which are expected to be recognized over a weighted-average period of 1.3 years, and unrecognized compensation expense of $9.1 million related to restricted stock awards which are expected to be recognized over a weighted-average period of 1.9 years. 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.

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 have further decreased during the first 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 have continued to fall into the first 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.

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 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 quarter of 2009, our net cash provided by operating activities from continuing operations was $50.7 million, representing a 64% decrease as compared to $139.7 million generated during the 2008 period. The $89.0 million decrease in 2009 was primarily due to a decrease of $122.6 million in revenues, mainly attributable to lower oil and natural gas prices during the first part of the year, offset in part by lower operating costs and lower severance taxes due to lower oil and gas sales.

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 March 31, 2009 and 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 balance sheets.

Existing Credit Facility. We had borrowings of $236.7 million under our bank credit facility at March 31, 2009, and $180.7 million in borrowings at December 31, 2008. Our bank credit facility at March 31, 2009 consisted of a $500.0 million credit facility with a syndicate of ten banks, which is based entirely on assets from continuing operations 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 March 31, 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 access to funds from our credit facility is not restricted under any "material adverse condition" clause, a clause that is common for credit agreements to include. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect. 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 current state of the financial and credit markets.

Working Capital. Our working capital increased from a deficit of $75.4 million at December 31, 2008, to a deficit of $33.9 million at March 31, 2009. The increase primarily resulted in a decrease in accounts payable and accrued capital costs as the amount spent on capital activities has decreased when compared to prior year levels.

Debt Maturities. Our credit facility, with a balance of $236.7 million at March 31, 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.

Cash Used in Investing Activities. In the first quarter of 2009 our oil and gas property additions were $103.4 million. This amount decreased by $73.0 million as compared to the first quarter 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 first quarter 2009 cash based amounts were significantly higher than accrual based capital expenditures as we reduced our accounts payable and accrued capital cost balances from year-end levels. These 2009 expenditures were funded by $50.7 million of cash provided by operating activities from continuing operations and $56.0 million in proceeds from our line of credit borrowings.

We drilled four wells in the first quarter of 2009. One development well was completed in the Southeast Louisiana core area, while one 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.

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 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 the PV-10 and volumetric calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, year-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.

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 the effects of such pricing volatility are expected to continue 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 March 31, 2009, we had no outstanding derivative instruments in place for future production.

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 March 31, 2009, we had borrowings of $236.7 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 designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. Our chief executive officer and chief financial officer have evaluated our disclosure controls and procedures as of the end of the period covered by this report and have concluded that such disclosure controls and procedures are effective in ensuring that material information required to be disclosed in this report is accumulated and communicated to them and our management to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first quarter 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.

There have been no material changes in our risk factors from those disclosed in our 2008 Annual Report on Form 10-K.

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

The following table summarizes repurchases of our common stock occurring during the first 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)
01/01/09 – 01/31/09 (1)	1,368	$ 16.33	---	$ ---
02/01/09 – 02/28/09 (1)	40,034	15.15	---	---
03/01/09 – 03/31/09 (1)	836	5.76	---	---
Total	42,238	$ 15.00	---	$ ---

(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.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

10.1*	Fifth Amendment to First Amended and Restated Credit Agreement effective as of May 1, 2009, by and among Swift Energy Company and Swift Energy Operating, LLC, and J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, N.A., as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Document Agent.
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: May 7, 2009	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: May 7, 2009	By:	/s/ David W. Wesson David W. Wesson Controller and Principal Accounting Officer

Exhibit Index

10.1*	Fifth Amendment to First Amended and Restated Credit Agreement effective as of May 1, 2009, by and among Swift Energy Company and Swift Energy Operating, LLC, and J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, N.A., as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Document Agent.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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