SWIFT ENERGY CO
Form 10-Q
May 08, 2008

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, 2008
Commission File Number 1-8754

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

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

16825 Northchase Drive, Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)

Securities registered pursuant to Section 12(b) of the Act:

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

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

Indicate by check mark whether the registrant 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

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)	30,535,841 Shares
(Class of Stock)	(Outstanding at April 30, 2008)

1

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2008
INDEX

C Certification of CFO Pursuant to rule 13a-14(a)
Certification of CEO & CFO Pursuant to Section 1350

2

Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	March 31, 2008 (Unaudited)	December 31, 2007
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 10,156	$ 5,623
Accounts receivable-		
Oil and gas sales	67,549	72,916
Joint interest owners	1,884	1,587
Other Receivables	1,709	1,324
Deferred tax asset	16,510	8,055
Other current assets	11,673	13,896
Current assets held for sale	93,446	96,549
Total Current Assets	202,927	199,950
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	2,752,116	2,610,469
Unproved properties	108,388	106,643
	2,860,504	2,717,112
Furniture, fixtures, and other equipment	33,349	33,064
	2,893,853	2,750,176
Less – Accumulated depreciation, depletion, and amortization	(1,042,913)	(989,981)
	1,850,940	1,760,195
Other Assets:		
Debt issuance costs	6,971	7,252
Restricted assets	1,588	1,654
	8,559	8,906
	$ 2,062,426	$ 1,969,051
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 78,793	$ 89,281
Accrued capital costs	72,117	94,947
Accrued interest	9,095	7,558
Undistributed oil and gas revenues	5,694	10,309
Current liabilities associated with assets held for sale	8,164	8,066
Total Current Liabilities	173,863	210,161
Long-Term Debt	623,400	587,000
Deferred Income Taxes	337,620	302,303
Asset Retirement Obligation	32,372	31,066
Other Long-Term Liabilities	2,407	2,467
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, 30,939,581 and 30,615,010 shares issued, and 30,508,425 and 30,178,596 shares outstanding, respectively	309	306
Additional paid-in capital	416,548	407,464
Treasury stock held, at cost, 431,156 and 436,414 shares, respectively	(8,196)	(7,480)
Retained earnings	484,539	436,178
Accumulated other comprehensive loss, net of income tax	(436)	(414)
	892,764	836,054
	$ 2,062,426	$ 1,969,051

See accompanying Notes to Consolidated Financial Statements.

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Revenues:		
Oil and gas sales	$ 199,973	$ 130,222
Price-risk management and other, net	(1,013)	(143)
	198,960	130,079
Costs and Expenses:		
General and administrative, net	9,919	7,589
Depreciation, depletion, and amortization	52,494	41,722
Accretion of asset retirement obligation	454	341
Lease operating cost	26,425	15,714
Severance and other taxes	22,136	16,050
Interest expense, net	8,690	6,746
	120,118	88,162
Income from Continuing Operations Before Income Taxes	78,842	41,917
Provision for Income Taxes	29,007	15,472
Income from Continuing Operations	49,835	26,445
Income (Loss) from Discontinued Operations, net of taxes	(1,474)	1,143
Net Income	$ 48,361	$ 27,588
Per Share Amounts-		
Basic: Income from Continuing Operations	$ 1.64	$ 0.89
Income (Loss) from Discontinued Operations, net of taxes	(0.05)	0.04
Net Income	$ 1.59	$ 0.92
Diluted: Income from Continuing Operations	$ 1.61	$ 0.87
Income (Loss) from Discontinued Operations, net of taxes	(0.05)	0.04
Net Income	$ 1.56	$ 0.90
Weighted Average Shares Outstanding	30,347	29,830

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, 2006	$ 302	$ 387,556	$ (6,125)	$ 415,868	$ 316	$ 797,917
Stock issued for benefit plans (32,817 shares)	-	953	471	-	-	1,424
Stock options exercised (239,650 shares)	2	3,168	-	-	-	3,170
Purchase of treasury shares (42,145 shares)	-	-	(1,826)	-	-	(1,826)
Adoption of FIN 48	-	-	-	(977)	-	(977)
Excess tax benefits from stock-based awards	-	613	-	-	-	613
Employee stock purchase plan (17,678 shares)	-	619	-	-	-	619
Issuance of restricted stock (187,678 shares)	2	(2)	-	-	-	-
Amortization of stock compensation	-	14,557	-	-	-	14,557
Comprehensive income:						
Net income	-	-	-	21,287	-	21,287
Other comprehensive loss	-	-	-	-	(730)	(730)
Total comprehensive income						20,557
Balance, December 31, 2007	$ 306	$ 407,464	$ (7,480)	$ 436,178	$ (414)	$ 836,054
Stock issued for benefit plans (39,152 shares) (2)	-	1,018	671	-	-	1,689
Stock options exercised (171,666 shares) (2)	2	2,941	-	-	-	2,943
Purchase of treasury shares (33,894 shares) (2)	-	-	(1,387)	-	-	(1,387)
Excess tax benefits from stock-based awards (2)	-	467	-	-	-	467
Employee stock purchase plan (25,645 shares) (2)	-	944	-	-	-	944
Issuance of restricted stock (127,260 shares) (2)	1	(1)	-	-	-	-
Amortization of stock compensation (2)	-	3,715	-	-	-	3,715
Comprehensive income:						
Net income (2)	-	-	-	48,361	-	48,361
Other comprehensive loss (2)	-	-	-	-	(22)	(22)
						48,339

Total comprehensive income (2)						
Balance, March 31, 2008 (2)	$ 309	$ 416,548	$ (8,196)	$ 484,539	$ (436)	$ 892,764

(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,	
	2008	2007
Cash Flows from Operating Activities:		
Net income	$ 48,361	$ 27,588
Plus (income) loss from discontinued operations, net of taxes	1,474	(1,143)
Adjustments to reconcile net income to net cash provided by operation activities -		
Depreciation, depletion, and amortization	52,494	41,722
Accretion of asset retirement obligation	454	341
Deferred income taxes	28,428	15,446
Stock-based compensation expense	2,632	2,431
Other	2,409	(2,179)
Change in assets and liabilities-		
Decrease in accounts receivable	2,272	586
Decrease in accounts payable and accrued liabilities	(950)	(7,261)
Increase (decrease) in income taxes payable	579	(884)
Increase in accrued interest	1,537	1,928
Cash Provided by operating activities – continuing operations	139,690	78,575
Cash Provided by operating activities – discontinued operations	2,822	7,392
Net Cash Provided by Operating Activities	142,512	85,967
Cash Flows from Investing Activities:		
Additions to property and equipment	(176,402)	(110,340)
Proceeds from the sale of property and equipment	79	89
Net cash received as operator of partnerships and joint ventures	---	467
Cash Used in investing activities – continuing operations	(176,323)	(109,784)
Cash Used in investing activities – discontinued operations	(1,023)	(6,979)
Net Cash Used in Investing Activities	(177,346)	(116,763)
Cash Flows from Financing Activities:		
Net proceeds from bank borrowings	36,400	32,600
Net proceeds from issuances of common stock	3,887	1,029
Excess tax benefits from stock-based awards	467	---
Purchase of treasury shares	(1,387)	(928)
Cash provided by financing activities – continuing operations	39,367	32,701
Cash provided by financing activities – discontinued operations	---	---
Net Cash Provided by financing activities	39,367	32,701

Net Increase in Cash and Cash Equivalents	$	4,533	$	1,905
Cash and Cash Equivalents at Beginning of Period		5,623		1,058
Cash and Cash Equivalents at End of Period	$	10,156	$	2,963
Supplemental Disclosures of Cash Flows Information:				
Cash paid during period for interest, net of amounts capitalized	$	6,872	$	4,507
Cash paid during period for income taxes	$	---	$	1,000

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, 2007 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 Company ("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. Certain amounts have been reclassified to present the Company's New Zealand operations as discontinued operations. Unless otherwise indicated, information presented in the notes to the condensed consolidated financial statements relates only to Swift'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 of future costs to develop and produce reserves,
- accruals related to oil and natural gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage,
- 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.

7

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, 2008 and 2007, such internal costs capitalized totaled $6.8 million and $7.3 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the quarters ended March 31, 2008 and 2007, capitalized interest on unproved properties totaled $2.0 million and $2.5 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 two and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

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

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at March 31, 2008 consisted of oil and natural gas price floors with strike prices lower than the period-end price and did not materially affect this calculation. This calculation is done on a country-by-country basis.

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

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices decline significantly from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that 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, a non-cash write-down 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 sizable 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 collectibility 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, 2008, 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, 2008 and December 31, 2007, 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.

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 quarters of 2008 and 2007, we recognized net losses of $1.0 million and $0.3 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of 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. At March 31, 2008, the Company had recorded $0.4 million, net of taxes of $0.3 million, of derivative losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying condensed consolidated balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for the first quarters of 2008 and 2007 were not material. All amounts currently held in "Accumulated other comprehensive loss, net of income tax" will be realized within the next three months when the forecasted sale of hedged production occurs.

At March 31, 2008, we had in place gas price floors in effect for the contract months of April 2008 through June 2008 that cover a portion of our gas production for April 2008 to June 2008. The natural gas price floors cover notional volumes of 2,775,000 MMBtu, with a weighted average floor price of $7.68 per MMBtu. Our natural gas price floors in place at March 31, 2008 are expected to cover approximately 45% to 50% of our estimated natural gas production from April 2008 to June 2008.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive loss, net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive loss, net of income tax" and recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of 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. The fair value of these instruments at March 31, 2008, was less than $0.1 million and is recognized on the accompanying condensed consolidated balance sheet in "Other current assets."

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, to the extent they do not exceed actual costs incurred, are recorded as a reduction to "General and administrative, net." Our supervision fees are based on COPAS determined rates. The amount of supervision fees charged in the first three months of 2008 and 2007 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $3.9 million and $2.6 million in the first three months of 2008 and 2007, 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 $4.6 million at March 31, 2008 and $4.2 million at December 31, 2007.

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. This was also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. We did not recognize significant increases or decreases in unrecognized tax benefits during the quarters ended March 31, 2008 and 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of March 31, 2008 no interest or penalties relating to income taxes have been incurred or recognized. Our cumulative interest exposure on unrecognized tax benefits is not material.

Our U.S. Federal and State of 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.

In the third quarter of 2007 we increased the valuation allowance for our capital loss carryforward assets by $2.6 million to cover the full value of the carryforward. The increase in the valuation allowance was due to changes in the Company's property disposition plans and increased income tax expense of $2.6 million in that period.

Accounts Payable and Accrued Liabilities. Included in "Accounts payable and accrued liabilities," on the accompanying condensed consolidated balance sheets, at March 31, 2008 and December 31, 2007 are liabilities of approximately $15.3 million and $12.6 million, respectively, which represent the amounts by which checks issued, but not presented by vendors to the Company's banks for collection, exceeded balances in the applicable disbursement bank accounts.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the provisions of SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At March 31, 2008, we recorded $0.4 million, net of taxes of less than $0.3 million, of derivative losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2008 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2007	$ (658)	$ 244	$ (414)
Change in fair value of cash flow hedges	(1,018)	378	(640)
Effect of cash flow hedges settled during the period	982	(364)	618
Other comprehensive loss at March 31, 2008	$ (694)	$ 258	$ (436)

Total comprehensive income was $48.3 million and $27.1 million for the first quarters of 2008 and 2007, respectively.

Asset Retirement Obligation. We record these obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the well is expected to deplete. 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):

(in thousands)	2008	2007
Asset Retirement Obligation recorded as of January 1	$ 34,459	$ 28,794
Accretion expense for the three months ended March 31	454	341
Liabilities incurred for new wells and facilities construction	227	139
Reductions due to sold, or plugged and abandoned wells	(25)	---
Asset Retirement Obligation as of March 31	$ 35,115	$ 29,274

At March 31, 2008 and December 31, 2007, approximately $2.7 million and $3.4 million, 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 September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosures regarding 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. SFAS No. 157 was effective for fiscal periods beginning after November 15, 2007. On February 12, 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. For Swift, this action defers the effective date for those assets and liabilities until January 1, 2009. The adoption of this statement did not have a material impact on our financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115. SFAS No. 159 permits entities to measure eligible assets and liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 159 on January 1, 2008 and did not elect to apply the fair value method to any eligible assets or liabilities at that time.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) provides enhanced guidance related to the measurement of identifiable assets acquired, liabilities assumed and disclosure of information related to business combinations and their effect on the Company. This Statement, together with the International Accounting Standards Board's (IASB) IFRS 3, Business Combinations, completes a joint effort by the FASB and IASB to improve financial reporting about business combinations and promotes the international convergence of accounting standards. For Swift, SFAS No. 141(R) applies prospectively to business combinations in 2009 and is not subject to early adoption. We will evaluate the impact of SFAS No. 141(R) on business combinations and related valuations as we have business acquisitions in the future.

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. We believe that the adoption of this statement will not have a material impact on our financial position or results of operations.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007, for additional information related to these share-based compensation plans.

We follow SFAS No. 123 (R), "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 and $0.3 million for the three months ended March 31, 2008 and 2007, respectively. The benefit for the first quarter of 2008 and 2007 that was not recognized in the financial statements as these benefits had not been realized due to a tax net operating loss position for these quarters was $0.9 million and $0.3 million, respectively.

Net cash proceeds from the exercise of stock options were $2.9 million and $0.4 million for the three months ended March 31, 2008 and 2007. The actual income tax benefit realized from stock option exercises was $1.5 million and $0.1 million for the same periods.

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 $2.4 million and $2.2 million for the quarters ended March 31, 2008 and 2007, respectively, and stock compensation recorded in lease operating cost was $0.2 million and $0.1 million for the quarters ended March 31, 2008 and 2007, respectively. We also capitalized $1.1 million and $1.0 million of stock compensation in the first quarters of 2008 and 2007, 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, 2008	Three Months Ended March 31, 2007
Dividend yield	0%	0%
Expected volatility	39.0%	38.6%
Risk-free interest rate	2.5%	4.8%
Expected life of options (in years)	4.8	6.5
Weighted-average grant-date fair value	$ 15.96	$ 20.56

The expected term for grants issued during 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 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, 2008, there was $4.6 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.6 years. The following table represents stock option activity for the three months ended March 31, 2008:

	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	1,449,240	$ 28.47
Options granted	166,048	$ 43.94
Options canceled	(4,000)	$ 43.48
Options exercised	(202,133)	$ 21.83
Options outstanding, end of period	1,409,155	$ 31.17
Options exercisable, end of period	829,516	$ 27.82

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at March 31, 2008 was $20.0 million and 5.6 years and $14.7 million and 4.3 years, respectively. Total intrinsic value of options exercised during the three months ended March 31, 2008 was $5.0 million.

Restricted Stock

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007, 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 five 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, 2008, we had unrecognized compensation expense of approximately $24.5 million associated with these awards which are expected to be recognized over a weighted-average period of 1.7 years. The total fair value of shares vested during the first three months ended March 31, 2008 was $5.3 million.

The following table represents restricted stock activity for the three months ended March 31, 2008:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	596,590	$ 41.60
Restricted shares granted	272,840	$ 43.24
Restricted shares canceled	(6,820)	$ 43.44
Restricted shares vested	(126,649)	$ 41.61
Restricted shares outstanding, end of period	735,961	$ 42.16

(4) Earnings Per Share

Basic earnings per share ("Basic EPS") have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share ("Diluted EPS") for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Certain of our stock options and restricted stock that would potentially dilute Basic EPS in the future were also antidilutive for the periods ended March 31, 2008 and 2007, 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, 2008 and 2007 (in thousands, except per share amounts):

	2008			2007		
	Income from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount
Basic EPS:						
Net Income from continuing operations, and Share Amounts	$ 49,835	30,347	$ 1.64	$ 26,445	29,830	$ 0.89
Dilutive Securities:						
Restricted Stock	--	178		--	110	
Stock Options	--	400		--	556	
Diluted EPS:						
Net Income from continuing operations, and assumed Share conversions	$ 49,835	30,925	$ 1.61	$ 26,445	30,497	$ 0.87

Options to purchase approximately 1.4 million shares at an average exercise price of $31.17 were outstanding at March 31, 2008, while options to purchase 1.7 million shares at an average exercise price of $26.66 were outstanding at March 31, 2007. Approximately 1.0 million and 1.2 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended March 31, 2008 and 2007, respectively, 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. Employee restricted stock grants of 0.6 million shares were not included in the computation of Diluted EPS for the three months ended March 31, 2008 and 2007 because these restricted stock grants were antidilutive in that the sum of the unrecognized compensation expense and excess tax benefits recognized as proceeds under the treasury stock method was greater than the average closing market price for the common shares during that period.

(5) Long-Term Debt

Our long-term debt as of March 31, 2008 and December 31, 2007, was as follows (in thousands):

	March 31, 2008	December 31, 2007
Bank Borrowings	$ 223,400	$ 187,000
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	$ 623,400	$ 587,000

Bank Borrowings. At March 31, 2008, we had borrowings of $223.4 million under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base of $400.0 million, based entirely on assets from continuing operations, and expires in October 2011. The interest rate is either (a) the lead bank's prime rate (5.25% at March 31, 2008) or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. In April 2007 we increased the borrowing base to $350.0 million from $250.0 million; and effective November 2007, we further increased it to $400.0 million. In September 2007, we increased the commitment amount under the borrowing base to $350.0 million from $250.0 million. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred an additional $0.3 million of debt issuance costs related to the increase of the commitment amount in 2007, which is included in "Debt issuance costs" on the accompanying condensed consolidated balance sheets and will be amortized to interest expense over the life of the facility.

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. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The borrowing base amount is re-determined at least every six months and the next scheduled borrowing base review is in November 2008.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $2.9 million and $1.4 million for the first quarters of 2008 and 2007, 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, 2008 and 2007.

Senior Notes Due 2011. These notes consist of $150.0 million of 7-5/8% senior notes, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $3.0 million for both the three months ended March 31, 2008 and 2007, respectively.

Senior Subordinated Notes Due 2012. These notes consisted of $200.0 million of 9-3/8% senior subordinated notes due May 2012, which were issued on April 16, 2002 and were scheduled to mature on May 1, 2012. Interest on these notes was payable semiannually on May 1 and November 1. As of June 18, 2007, we redeemed all $200.0 million of these notes. The costs were comprised of approximately $9.4 million of premium paid to redeem the notes, and $3.4 million to write-off unamortized debt issuance costs.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $4.8 million for the three months ended March 31, 2007.

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, 2008.

The maturities on our long-term debt are $0 for 2008, 2009 and 2010, $373.4 million for 2011, and $250 million thereafter.

We have capitalized interest on our unproved properties in the amount of $2.0 million and $2.5 million for the three months ended March 31, 2008 and 2007, respectively.

(6) Discontinued Operations

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets for approximately $87.8 million in cash before purchase price adjustments. In May 2008, we agreed to sell our remaining New Zealand permit for $15.0 million before purchase price adjustments, with payments being received over the next 30 months and secured by unconditional letters of credit. Accordingly, our 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. We expect to close both asset sales during the second quarter of 2008. Proceeds from the New Zealand assets sale will be used to pay down a portion of our credit facility.

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 sheet for prior periods. During the fourth quarter of 2007 and 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 non-cash asset write-downs of $143.2 million and $2.1 million, respectively, related to these assets. These write-downs are recorded in “Income (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 $0.5 million, and we expect to record a non-cash gain of $12.8 million upon closing the sale of that permit.

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Oil and gas sales	$ 8,305	$ 10,807
Other revenues	574	207
Total revenues	8,879	11,014
Depreciation, depletion, and amortization	2,620	5,925
Other operating expenses	5,895	4,273
Non-cash write-down of property and equipment	2,096	---
Total expenses	10,611	10,198
Income (loss) from discontinued operations before income taxes	(1,732)	816
Income tax benefit	(258)	(327)
Income (loss) from discontinued operations, net of taxes	$ (1,474)	$ 1,143
Income (loss) per common share from discontinued operations-diluted	$ (0.05)	$ 0.04
Sales volumes (MBoe)	248	384
Cash flow provided by operating activities	$ 2,822	$ 7,392
Capital expenditures	$ 1,023	$ 6,979

Total assets for our discontinued operations were $105.9 million at March 31, 2008 and $110.6 million at December 31, 2007. For the quarters ended March 31, 2008 and 2007, our capitalized general and administrative expenses totaled $0.5 million and $1.2 million, respectively.

As of March 31, 2008, we held $93.4 million of property and equipment, net in “Current assets held for sale” and $8.2 million of asset retirement obligations in “Current liabilities associated with assets held for sale”; and at December 31, 2007, we held $96.5 million of property and equipment, net in “Current assets held for sale” and $8.1 million of asset retirement obligations in “Current liabilities associated with assets held for sale” on the accompanying condensed consolidated balance sheets.

(7) Acquisitions and Dispositions

In October 2007, we acquired interests in three South Texas fields in the Maverick Basin from Escondido Resources, LP. The property interests are located in the Sun TSH field in La Salle County, the Briscoe Ranch field primarily in Dimmit County, and the Las Tiendas field in Webb County. We refer to these properties as the Cotulla properties. We paid approximately $248.2 million in cash for these interests including purchase price adjustments. After taking into account internal acquisition costs of $2.5 million, our total cost was $250.7 million. We allocated $241.8 million of the acquisition price to “Proved Properties,” $8.9 million to “Unproved Properties,” and recorded a liability for $0.6 million to “Asset retirement obligation” on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in South Texas. The revenues and expenses from these properties have been included in our accompanying condensed consolidated statement of income from the date of acquisition forward; however, given that the acquisitions closed in the fourth quarter of 2007, these amounts were not material to our full year 2007 results.

(8) 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, 2008				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 97,265	$ 105,662	$ ---	$ 202,927
Property and equipment	---	1,850,683	257	---	1,850,940
Investment in subsidiaries (equity method)	892,764	---	818,342	(1,711,106)	---
Other assets	---	28,641	---	(20,082)	8,559
Total assets	$ 892,764	$ 1,976,589	$ 924,261	$ (1,731,188)	$ 2,062,426
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 162,190	$ 31,755	$ (20,082)	$ 173,863
Long-term liabilities	---	996,057	(258)	---	995,799
Stockholders' equity	892,764	818,342	892,764	(1,711,106)	892,764
Total liabilities and stockholders' equity	$ 892,764	$ 1,976,589	$ 924,261	$ (1,731,188)	$ 2,062,426

(in thousands)	December 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ ---	$ 89,513	$ 110,437	$ ---	$ 199,950
Property and equipment	---	1,760,195	---	---	1,760,195
Investment in subsidiaries (equity method)	836,054	---	760,158	(1,596,212)	---
Other assets	---	28,828	---	(19,922)	8,906
Total assets	$ 836,054	$ 1,878,536	$ 870,595	$ (1,616,134)	$ 1,969,051
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 195,542	$ 34,541	$ (19,922)	$ 210,161
Long-term liabilities	---	922,836	---	---	922,836

Stockholders' equity	836,054	760,158	836,054	(1,596,212)	836,054
Total liabilities and stockholders' equity	$ 836,054	$ 1,878,536	$ 870,595	$ (1,616,134)	$ 1,969,051

Condensed Consolidating Statements of Income

(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 before the following:	---	78,842	---	---	78,842
Equity in net earnings of subsidiaries	48,361	---	49,835	(98,196)	---
Income from continuing operations, before income taxes	48,361	78,842	49,835	(98,196)	78,842
Income tax provision	---	29,007	---	---	29,007
Income 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	$ 48,361	$ 49,835	$ 48,361	$ (98,196)	$ 48,361

(in thousands)	Three Months Ended March 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 130,079	$ ---	$ ---	$ 130,079
Expenses	---	88,162	---	---	88,162
Income before the following:	---	41,917	---	---	41,917
Equity in net earnings of subsidiaries	27,588	---	26,445	(54,033)	---
Income from continuing operations, before income taxes	27,588	41,917	26,445	(54,033)	41,917
Income tax provision	---	15,472	---	---	15,472

Income from continuing operations	27,588	26,445	26,445	(54,033)	26,445
Income from discontinued operations, net of taxes	---	---	1,143	---	1,143
Net income	$ 27,588	$ 26,445	$ 27,588	$ (54,033)	$ 27,588

Condensed Consolidating Statements of Cash Flow

(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

(in thousands)	Three Months Ended March 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 78,575	$ 7,392	$ ---	$ 85,967
Cash flow from investing activities	---	(110,417)	(6,979)	633	(116,763)
Cash flow from financing activities	---	32,701	633	(633)	32,701
Net increase in cash	---	859	1,046	---	1,905
Cash, beginning of period	---	50	1,008	---	1,058
Cash, end of period	$ ---	$ 909	$ 2,054	$ ---	$ 2,963

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

Item 2.

You should read the following discussion and analysis in conjunction with our financial information and our condensed consolidated financial statements and notes thereto included in this report and our Annual Report on Form 10-K for the year ended December 31, 2007. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Statements" on page 33 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 oil in the state of Louisiana, and due to our South Louisiana operations, we are predominantly an oil producer, with oil constituting 55% of our first quarter 2008 domestic production, and oil and natural gas liquids ("NGLs") together making up 68% of our first quarter 2008 domestic production. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in recent periods.

In December 2007, we agreed to sell substantially all of our New Zealand assets to Origin Energy Limited for approximately $87.8 million in cash before purchase price adjustments, and in May 2008 agreed to sell our remaining permit for $15.0 million before purchase price adjustments with payments being received over the next 30 months and secured by unconditional letters of credit. Both of these asset sales are expected to close in the second quarter of 2008. Accordingly, our New Zealand operations have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. The pending sale of these assets resulted in a first quarter 2008 non-cash charge of approximately $2.1 million based on the selling price and terms in place at that time. Upon closing of the sale of our remaining permit, we expect to record a non-cash gain of approximately $12.8 million. We expect to realize total cash proceeds of between $95 million and $100 million from the sale of all of our New Zealand assets and after collection on the corresponding receivable. Proceeds from the New Zealand assets sale will be used to pay down a portion of our credit facility.

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.

In the first quarter of 2008 we had strong income and cash flows. Income from continuing operations increased 88% to $49.8 million and cash flows from operating activities from continuing operations increased 78% to $139.7 million, in each case compared to the first quarter of 2007. Production from our continuing operations increased 1% to 2.57 MMBoe, due to increased production in our South Texas regions offset by production declines in our South Louisiana region. We also had record quarterly revenues of $199.0 million for the first three months of 2008, an increase of 53% over comparable 2007 levels. Our weighted average sales price received increased 51% to $77.80 per Boe for the first quarter of 2008 from $51.38 received during the first quarter of 2007. Our $69.8 million, or 54%, increase in oil and gas sales revenues resulted from 72% higher oil prices, 50% higher NGL prices, and 35% higher natural gas prices during the 2008 period.

23

During the first quarter of 2008, our overall costs and expenses increased 36% when compared to the same 2007 period. The largest increase in these costs and expenses was attributable to 26% higher depreciation, depletion and amortization expense, due to our larger depletable property base and higher production volumes. Lease operating expense also increased 68% due to higher workover costs as we increased the number of workovers performed in the current period, a higher well count mainly from our South Texas property acquisition in 2007, and higher NGL and natural gas processing costs. Severance and other taxes also increased 38% mainly due to increased oil and gas revenues. We expect cost pressures to continue to affect the industry throughout the remainder of 2008, with tightening availability of experienced crews and personnel as well as increasing costs of services, goods, and basic equipment. In the inflationary cost environment prevalent in the industry today, we will continue to focus on capital efficiency to manage those costs and expenses.

Lake Washington is our most significant field, and provides approximately 51% of our domestic production. In the first quarter of 2008, production at Lake Washington fell 11% from fourth quarter 2007 levels. In the first quarter of 2008, along with experiencing natural declines in production as our wells mature, we reduced the choke size of several wells in the Newport area to preserve reservoir pressure in anticipation of the pressure maintenance program that commenced with the Westside facility start-up early in the second quarter of 2008. We continue to drill deeper wells at Lake Washington that have higher flowing pressure and higher associated natural gas content. The increased pressure from the newer wells has increased the operating pressure on our production facilities, negatively impacting the level of production from our older, existing wells. We are also handling higher volumes of produced water and additional artificial lift demand from the mature area of the field. We believe the pressure maintenance activities planned for 2008 and the Westside facility start-up will improve the majority of the production constraints experienced in the first quarter of 2008. In Bay de Chene, we signed a new marketing agreement in the first quarter of 2008 and increased takeaway capacity early in the second quarter. This increase in takeaway capacity will position us to increase production in this area during the remainder of 2008.

Our debt to capitalization ratio was 41% at both March 31, 2008 and year-end 2007. Our debt to domestic PV-10 ratio decreased to 14% at March 31, 2008 from 15% at year-end 2007, as higher period-end reserves prices were offset by increased borrowings against our line of credit at that date.

Our capital expenditures from continuing operations of $176.3 million increased by $66.5 million during the first three months of 2008 as compared to the same period in 2007, primarily due to an increase in our spending on drilling and development, predominantly in our South Louisiana and South Texas regions. These expenditures were primarily funded by $139.7 million of cash provided by operating activities from continuing operations, and an increase in debt levels of $36.4 million.

Our current 2008 capital expenditure budget is $475 million to $525 million, net of minor non-core dispositions and excluding any property acquisitions, which was recently increased from $425 million to $475 million. Based upon current market conditions, commodity prices, and our estimates, our capital expenditures for 2008 should be within our anticipated cash flow from operations. We currently have budgeted approximately two-thirds of these amounts for our South Louisiana region, and on an overall basis three-fourths for developmental activities. For the full year 2008, we are targeting production from our continuing operations to increase 10% to 15% and domestic proved reserves to increase 5% to 9% both over 2007 levels. We may also further increase our capital expenditure budget if commodity prices rise during the year or if strategic opportunities warrant. If 2008 capital expenditures exceed our cash flow from operating activities, we can fund these expenditures with funds drawn under our credit facility.

During the remainder of 2008, we plan to further develop our inventory of properties in South Louisiana using our expertise and experience gained in successfully expanding and developing Lake Washington, together with significant 3-D seismic information, to exploit our other prospect areas covered by similar geological features. This broad prospect inventory will allow us to be selective in choosing drilling opportunities so we can create long-life reserves while at the same time raising our production.

Results of Continuing Operations — Three Months Ended March 31, 2008 and 2007

Revenues. Our revenues in the first quarter of 2008 increased by 53% compared to revenues in the same period in 2007, primarily due to higher commodity prices, along with higher NGL and natural gas volumes. Revenues for both periods were substantially comprised of oil and gas sales. Crude oil production was 55% of our production volumes in the first quarter of 2008 and 70% of our production in the first quarter of 2007. Natural gas production was 32% of our production volumes in the first quarter of 2008 and 25% in the first quarter of 2007.

Our domestic areas are divided into the following regions: Lake Washington region includes the Lake Washington and Bay de Chene areas. The North Lafayette region includes the Brookeland, Masters Creek, and South Bearhead Creek areas. The South Lafayette region includes the Cote Blanche Island, Horseshoe Bayou/Bayou Sale, Jeanerette, and Bayou Penchant areas. The South Texas region includes the AWP Olmos and Cotulla areas. The most significant property in our other category is the High Island area. 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, 2008 and 2007:

Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales Volumes (MBoe)	
	2008	2007	2008	2007
Lake Washington	$ 128.7	$ 96.6	1,466	1,746
North Lafayette	17.9	7.7	227	175
South Lafayette	11.9	10.9	160	233
South Texas	38.4	12.5	665	312
Other	3.1	2.5	52	68
Total	$ 200.0	$ 130.2	2,570	2,534

Oil and gas sales for the first quarter of 2008 increased by 54%, or $69.8 million, from the level of those revenues for the comparable 2007 period, and our net sales volumes in the first quarter of 2008 increased by 1%, or less than 0.1 MMBoe, over net sales volumes in the first quarter of 2007. Average prices for oil increased to $99.43 per Bbl in the first quarter of 2008 from $57.87 per Bbl in the first quarter of 2007. Average natural gas prices increased to $7.97 per Mcf in the first quarter of 2008 from $5.92 per Mcf in the first quarter of 2007. Average NGL prices increased to $59.80 per Bbl in the first quarter of 2008 from $39.90 per Bbl in the first quarter of 2007.

In the first quarter of 2008, our $69.8 million increase in oil, NGL, and natural gas sales resulted from:

- Volume variances that had a $5.8 million unfavorable impact on sales, with $20.4 million of decreases attributable to the 0.4 million Bbl decrease in oil sales volumes, offset by a $7.3 million increase due to the 0.2 million Bbl increase in NGL sales volumes, and a $7.3 million increase due to the 1.2 Bcf increase in natural gas sales volumes; and

- Price variances that had a $75.6 million favorable impact on sales, of which $59.0 million was attributable to the 72% increase in average oil prices received, $6.3 million was attributable to the 50% increase in NGL prices, and $10.3 million was attributable to the 35% increase in natural gas prices.

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, 2008	1,420	316	5.0	2,570	$ 99.43	$ 59.80	$ 7.97
Three Months Ended March 31, 2007	1,773	133	3.8	2,534	$ 57.87	$ 39.90	$ 5.92

During the first quarters of 2008 and 2007, we recognized net losses of $1.0 million and $0.3 million, respectively, related to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. Had these gains and losses been recognized in the oil and gas sales account, our average oil sales price would have been $99.01 and $57.87 for the first quarters of 2008 and 2007, and our average natural gas sales price would have been $7.88 and $5.85 for the first quarters of 2008 and 2007, respectively.

Costs and Expenses. Our expenses in the first quarter of 2008 increased $32.0 million, or 36%, compared to expenses in the same period of 2007.

Our first quarter 2008 general and administrative expenses, net, increased $2.3 million, or 31%, from the level of such expenses in the same 2007 period. The increases was primarily due to increased salaries and burdens associated with our expanded workforce and was partially offset by an increase in supervision fee reimbursements as we operated more wells in the 2008 period due to the acquisition of the Cotulla properties and increases in reimbursement rates. For the first quarters of 2008 and 2007, our capitalized general and administrative costs totaled $6.8 million and $7.3 million, respectively. Our net general and administrative expenses per Boe produced increased to $3.86 per Boe in the first quarter of 2008 from $2.99 per Boe in the first quarter of 2007. The portion of supervision fees recorded as a reduction to general and administrative expenses was $3.9 million and $2.6 million for three month periods ended March 31, 2008 and 2007.

DD&A increased $10.8 million, or 26%, in the first quarter of 2008, from levels in the first quarter of 2007. The increase is due to increases in the depletable oil and natural gas property base, and slightly higher production. Industry costs for services and goods have increased over the last three year period and have contributed to the increase in our DD&A expense. Our DD&A rate per Boe of production was $20.43 and $16.46 in the first quarters of 2008 and 2007, resulting from increases in the per unit cost of reserves additions.

We recorded $0.5 million and $0.3 million of accretions to our asset retirement obligation in the first quarters of 2008 and 2007, respectively.

Our lease operating costs increased $10.7 million, or 68%, over the level of such expenses in the same 2007 period. Lease operating costs increased during 2008 due to increased workover costs, additional costs from properties acquired in the fourth quarter of 2007, increasing costs for industry goods and services, and higher natural gas and NGL processing costs in 2008. Our lease operating costs per Boe produced were $10.28 and $6.20 in the first quarters of 2008 and 2007, respectively.

Severance and other taxes increased $6.1 million, or 38%, over levels in the first quarter of 2007. The increase in the 2008 period was due primarily to higher commodity prices along with an increase in ad valorem tax expense. Severance and other taxes as a percentage of oil and gas sales were approximately 11.1% and 12.3% in the first quarters of 2008 and 2007, 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 2008 compared to the first quarter of 2007, the overall percentage of severance costs to sales also decreased.

Our total interest cost in the first quarter of 2008 was $10.7 million, of which $2.0 million was capitalized. Our total interest costs in the first quarter of 2007 was $9.3 million, of which $2.5 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in the first quarter of 2008 was primarily attributable to increase borrowings against our line of credit and lower capitalized costs, partially offset by lower interest expense resulting from our 2007 debt refinancing.

Our overall effective tax rate was 36.8% and 36.9% for the first quarters of 2008 and 2007. The effective tax rate for the first quarters of 2008 and 2007 were higher than the U.S. federal statutory rate of 35% primarily because of state income taxes.

Income from Continuing Operations. Our income from continuing operations for the first quarter of 2008 of $49.8 million was 88% higher than first quarter of 2007 income from continuing operations of $26.4 million due to higher commodity prices which were partially offset by increased costs.

Net Income. Our net income in the first quarter of 2008 of $48.4 million was 75% higher than our first quarter of 2007 net income of $27.6 million, mainly due to higher commodity prices which were partially offset by increased costs.

Discontinued Operations

In December 2007, Swift Energy agreed to sell substantially all of our New Zealand assets for approximately $87.8 million in cash before purchase price adjustments. In May 2008, we agreed to sell our remaining New Zealand permit for $15.0 million before purchase price adjustments, with payments being received over the next 30 months and secured by unconditional letters of credit. Accordingly, our 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. We expect to close both asset sales during the second quarter of 2008. Proceeds from the New Zealand assets sale will be used to pay down a portion of our credit facility.

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 sheet for prior periods. During the fourth quarter of 2007 and 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 non-cash asset write-downs of $143.2 million and $2.1 million, respectively, related to these assets. These write-downs are recorded in “Income (loss) from discontinued operations, net of taxes” on the accompanying condensed consolidated statement of income.

The book value of our remaining New Zealand permit is approximately $0.5 million, and we expect to record a non-cash gain of $12.8 million upon closing the sale of that permit.

As of March 31, 2008, operations in New Zealand had represented approximately 5% of our total assets and 9% of our first quarter 2008 sales volumes. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported under discontinued operations. The following table summarizes selected data pertaining to discontinued operations (in thousands except per share and per Boe amounts):

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Oil and gas sales	$ 8,305	$ 10,807
Other revenues	574	207
Total revenues	8,879	11,014
Depreciation, depletion, and amortization	2,620	5,925
Other operating expenses	5,895	4,273
Non-cash write-down of property and equipment	2,096	---
Total expenses	10,611	10,198
Income (loss) from discontinued operations before income taxes	(1,732)	816
Income tax benefit	(258)	(327)
Income (loss) from discontinued operations, net of taxes	$ (1,474)	$ 1,143
Income (loss) per common share from discontinued operations, net of taxes-diluted	$ (0.05)	$ 0.04
Total sales volumes (MBoe)	248	384
Oil sales volumes (MBbls)	34	62
Natural gas sales volumes (Bcf)	1.1	1.6
NGL sales volumes (MBbls)	32	48
Average sales price per Boe	$ 33.49	$ 28.12
Oil sales price per Bbl	$ 95.43	$ 64.01
Natural gas sales price per Mcf	$ 3.54	$ 3.36
NGL sales price per Bbl	$ 38.09	$ 26.96
Lease operating cost per Boe	$ 14.58	$ 6.74
Cash flow provided by operating activities	$ 2,822	$ 7,392
Capital expenditures	$ 1,023	$ 6,979

Total New Zealand assets at March 31, 2008 and December 31, 2007 were $105.9 million and $110.6 million.

Income (loss) from discontinued operations, net of tax, for the first quarter of 2008 decreased compared to the same period of 2007 primarily due a decrease in produced oil and natural gas volumes which reduced revenues and a non-cash write-down of property and equipment, partially offset by lower depletion expense due to lower production volumes. For the three months ended March 31, 2008 and 2007, our capitalized general and administrative expenses totaled $0.5 million and $1.2 million, respectively.

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:

28

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Dividend yield	0%	0%
Expected volatility	39.0%	38.6%
Risk-free interest rate	2.5%	4.8%
Expected life of options (in years)	4.8	6.5
Weighted-average grant-date fair value	$ 15.96	$ 20.56

The expected term for grants issued during 2008 was 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 were 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 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, 2008, there was $4.6 million of unrecognized compensation cost related to stock options, which are expected to be recognized over a weighted-average period of 1.6 years, and unrecognized compensation expense of $24.5 million related to restricted stock awards which are expected to be recognized over a weighted-average period of 1.7 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, 2007 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, 2007.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last three years and is at historical highs when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, 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 have fallen from highs in 2005 but continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, 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. This was also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. There were no increases or decreases in unrecognized tax benefits during the three months ended March 31, 2008.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of March 31, 2008 and 2007 no interest or penalties relating to income taxes have been incurred or recognized. Our cumulative interest exposure on unrecognized tax benefits is not material.

Our U.S. Federal and State of 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.

In the third quarter of 2007 we increased the valuation allowance for our capital loss carryforward assets by $2.6 million to cover the full value of the carryforward. The increase in the valuation allowance was due to changes in the Company's property disposition plans and increased income tax expense of $2.6 million in that period.

Liquidity and Capital Resources

During the first quarter of 2008, we relied upon our net cash provided by operating activities from continuing operations of $139.7 million, credit facility borrowings of $36.4 million, and cash balances to fund capital expenditures of $176.4 million. During the first quarter of 2007, we relied upon our net cash provided by operating activities from continuing operations of $78.6 million, credit facility borrowings of $32.6 million, and cash balances to fund capital expenditures of $110.3 million.

Net Cash Provided by Operating Activities. For the first quarter of 2008, our net cash provided by operating activities from continuing operations was $139.7 million, representing a 78% increase as compared to $78.6 million generated during the first quarter of 2007. The $61.1 million increase in 2008 was primarily due to an increase of $69.8 million in oil and gas sales, attributable to higher commodity prices and higher NGL and natural gas production, offset in part by lower oil production and increased expenses.

Accounts Receivable. We assess the collectibility of accounts receivable, and, based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At both December 31, 2007 and 2006, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Existing Credit Facility. We had borrowings of $223.4 million under our bank credit facility at March 31, 2008, and $187.0 million in borrowings at December 31, 2007. Our bank credit facility at March 31, 2008 consisted of a $500.0 million revolving line of credit with a $400.0 million borrowing base based entirely on assets from our continuing operations. The borrowing base is re-determined at least every six months and was increased by our bank group from $350.0 million to $400.0 million in November 2007. Under the terms of our bank credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. In September 2007, we increased the commitment amount from $250.0 million to $350.0 million. 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.

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. A “material adverse condition” clause can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have an adverse or material effect on operations, financial condition, prospects or properties, and would impair the ability to make timely debt repayments. 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.

Debt Maturities. Our credit facility, with a balance of $223.4 million at March 31, 2008, extends until October 3, 2011. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $250.0 million of 7-1/8% senior notes mature June 1, 2017.

Working Capital. Our working capital increased from a deficit of $10.2 million at December 31, 2007, to a surplus of $29.1 million at March 31, 2008. The improvement primarily resulted from a decrease in accounts payable and accrued capital costs and an increase in deferred tax assets.

Capital Expenditures. In the first quarter of 2008 we relied upon our net cash provided by operating activities from continuing operations of $139.7 million, credit facility borrowings of $36.4 million, and cash balances to fund capital expenditures of $176.4 million.

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 and will increase our processing capacity another 10,000 barrels per day by mid-2008.

We completed 35 of 36 wells in the first quarter of 2008, for a success rate of 97%. A total of three development wells were drilled successfully in the Lake Washington area, and 11 development wells were drilled successfully in the AWP Olmos area. In Bay de Chene, we successfully drilled one development well. We also drilled four successful development wells in the South Bearhead Creek area, drilled 13 successful development wells in the Cotulla area, drilled one successful development well in each of the Horseshoe Bayou/Bayou Sale and Jeanerette fields, and drilled one unsuccessful well in the Masters Creek field. One exploratory well was also drilled in the Cote Blanche Island field and is currently being evaluated.

During the last nine months of 2008, we anticipate drilling or participating in the drilling of up to an additional 23 to 30 wells in the Lake Washington core area, an additional 30 to 45 wells in the South Texas core area, two to three wells in the Lafayette North core area, and three to five wells in the Lafayette South core area.

New Accounting Pronouncements

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosures regarding 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. SFAS No. 157 was effective for fiscal periods beginning after November 15, 2007. On February 12, 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. For Swift, this action defers the effective date for those assets and liabilities until January 1, 2009. The adoption of this statement did not have a material impact on our financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115. SFAS No. 159 permits entities to measure eligible assets and liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 159 on January 1, 2008 and did not elect to apply the fair value method to any eligible assets or liabilities at that time.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) provides enhanced guidance related to the measurement of identifiable assets acquired, liabilities assumed and disclosure of information related to business combinations and their effect on the Company. This Statement, together with the International Accounting Standards Board's (IASB) IFRS 3, Business Combinations, completes a joint effort by the FASB and IASB to improve financial reporting about business combinations and promotes the international convergence of accounting standards. For Swift, SFAS No. 141(R) applies prospectively to business combinations in 2009 and is not subject to early adoption. We will evaluate the impact of SFAS No. 141(R) on business combinations and related valuations as we have business acquisitions in the future.

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. We believe the adoption of this statement will not have a material impact on our financial position or results of operations.

Forward-Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, 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," "should," "believe," or other words th 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; 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. The effects of such pricing volatility are expected to continue.

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. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- Price Floors – At March 31, 2008, we had in place price floors in effect through the June 2008 contract month for natural gas. The natural gas price floors cover notional volumes of 2,775,000 MMBtu, with a weighted average floor price of $7.68 per MMBtu. Our natural gas price floors in place at March 31, 2008, are expected to cover approximately 45% to 50% of our natural gas production during the second quarter of 2008. The fair value of these instruments at March 31, 2008, was less than $0.1 million and is recognized on the accompanying balance sheet in "Other current assets." There are no additional cash outflows for these price floors, as the cash premium was paid at inception of the hedge. The maximum loss that could be recognized on our income statement from these price floors when they settle during the second quarter of 2008 would be $0.7 million, which represents the original amount paid for these price floors less ineffectiveness previously recognized.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. 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.

Foreign Currency Risk. We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand Dollar. Fluctuations in rates between the New Zealand Dollar and U.S. Dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, natural gas and NGL sales contracts, and New Zealand income tax calculations, all denominated in New Zealand Dollars. We use the U.S. Dollar as our functional currency in New Zealand and as currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in “Income (loss) from discontinued operations, net of taxes” on the accompanying statements of income.

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, 2008, we had borrowings of $223.4 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 53 basis points and would not have a material adverse effect on our 2008 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 2008 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 2007 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 2008:

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)
01/01/08 – 01/31/08 (1)	781	$42.93	---	$---
02/01/08 – 02/29/08 (1)	32,649	40.79	---	---
03/01/08 – 03/31/08 (1)	464	45.97	---	---
Total	33,894	$40.91	---	$---

(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.

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 8, 2008	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: May 8, 2008	By:	/s/ David W. Wesson. David W. Wesson Controller and Principal Accounting Officer

Exhibit Index

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