SWIFT ENERGY CO
Form 10-Q
May 04, 2007

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, 2007

Commission File Number 1-8754

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

TEXAS	20-3940611
(State of Incorporation)	(I.R.S. Employer Identification No.)
16825 Northchase Drive, Suite 400 Houston, Texas	77060
(Address of principal executive offices)	(Zip Code)

(281) 874-2700
(Registrant's telephone number, including area code)

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)	29,897,074 Shares
(Class of Stock)	(Outstanding at April 30, 2007)

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

	March 31, 2007 (Unaudited)	December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,963	$ 1,058
Accounts receivable-		
Oil and gas sales	63,286	63,935
Joint interest owners	895	1,844
Other Receivables	1,035	1,231
Deferred Tax Asset	2,383	2,383
Other current assets	24,366	22,122
Total Current Assets	94,928	92,573
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	2,368,048	2,264,832
Unproved properties	107,426	112,136
	2,475,474	2,376,968
Furniture, fixtures, and other equipment	30,441	28,041
	2,505,915	2,405,009
Less – Accumulated depreciation, depletion, and amortization	(969,634)	(921,697)
	1,536,281	1,483,312
Other Assets:		
Debt issuance costs	7,071	7,382
Restricted assets	2,414	2,415
	9,485	9,797
	$ 1,640,694	$ 1,585,682
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 60,707	$ 74,425
Accrued capital costs	41,478	55,282
Accrued interest	10,692	8,764
Undistributed oil and gas revenues	9,709	7,504
Total Current Liabilities	122,586	145,975
Long-Term Debt	414,000	381,400
Deferred Income Taxes	239,357	224,967
Asset Retirement Obligation	34,122	33,695
Lease Incentive Obligation	1,668	1,728
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, 30,306,537 and 30,170,004 shares issued, and 29,891,374 and 29,742,918 shares outstanding, respectively	303	302
Additional paid-in capital	392,975	387,556
Treasury stock held, at cost, 415,163 and 427,086 shares, respectively	(6,582)	(6,125)
Retained earnings	442,479	415,868
Accumulated other comprehensive income (loss), net of income tax	(214)	316
	828,961	797,917
	$ 1,640,694	$ 1,585,682

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended	
	03/31/07	03/31/06
Revenues:		
Oil and gas sales	$ 141,029	$ 134,953
Price-risk management and other, net	64	1,216
	141,093	136,169
Costs and Expenses:		
General and administrative, net	8,529	7,687
Depreciation, depletion and amortization	47,647	35,406
Accretion of asset retirement obligation	386	292
Lease operating costs	18,304	14,394
Severance and other taxes	16,748	14,754
Interest expense, net	6,745	5,861
	98,359	78,394
Income Before Income Taxes	42,734	57,775
Provision for Income Taxes	15,146	20,460
Net Income	$ 27,588	$ 37,315
Per Share Amounts		
Basic: Net Income	$ 0.92	$ 1.28
Diluted: Net Income	$ 0.90	$ 1.24
Weighted Average Shares Outstanding	29,830	29,072

See accompanying notes to condensed 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	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2005	$ 295	$ 365,086	$ (6,446)	$ (5,850)	$ 254,303	$ (70)	$ 607,318
Stock issued for benefit plans (22,358 shares)	-	714	321	-	-	-	1,035
Stock options exercised (652,829 shares)	7	11,831	-	-	-	-	11,838
Adoption of SFAS No. 123R	-	(5,875)	-	5,850	-	-	(25)
Excess tax benefits from stock-based awards	-	4,811	-	-	-	-	4,811
Employee stock purchase plan (22,425 shares)	-	671	-	-	-	-	671
Issuance of restricted stock (35,776 shares)	-	-	-	-	-	-	-
Amortization of stock compensation	-	10,318	-	-	-	-	10,318
Comprehensive income:							
Net income	-	-	-	-	161,565	-	161,565
Other comprehensive income	-	-	-	-	-	386	386
Total comprehensive income							161,951
Balance, December 31, 2006	$ 302	$ 387,556	$ (6,125)	$ -	$ 415,868	$ 316	$ 797,917
Stock issued for benefit plans (32,817 shares) (2)	-	952	471	-	-	-	1,423

Stock options exercised (20,673 shares) (2)	-	411	-	-	-	-	411
Purchase of treasury shares (20,894 shares) (2)	-	-	(928)	-	-	-	(928)
Adoption of FIN 48 (2)	-	-	-	-	(977)	-	(977)
Employee stock purchase plan (17,678 shares) (2)	-	619	-	-	-	-	619
Issuance of restricted stock (98,182 shares) (2)	1	(1)	-	-	-	-	-
Amortization of stock Compensation (2)	-	3,438	-	-	-	-	3,438
Comprehensive income:							
Net income (2)	-	-	-	-	27,588	-	27,588
Other comprehensive loss (2)	-	-	-	-	-	(530)	(530)
Total comprehensive income (2)							27,058
Balance, March 31, 2007 (2)	$ 303	$ 392,975	$ (6,582)	$ -	$ 442,479	$ (214)	$ 828,961

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

See accompanying notes to condensed consolidated financial statements.

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Cash Flows from Operating Activities:		
Net income	$ 27,588	$ 37,315
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	47,647	35,406
Accretion of asset retirement obligation	386	292
Deferred income taxes	15,120	19,992
Stock-based compensation expense	2,431	1,710
Other	(2,587)	(3,120)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	1,599	(9,799)
Decrease in accounts payable and accrued liabilities	(7,261)	(189)
Increase (decrease) in income taxes payable	(884)	468
Increase in accrued interest	1,928	1,825
Net Cash Provided by Operating Activities	85,967	83,900
Cash Flows from Investing Activities:		
Additions to property and equipment	(113,374)	(77,963)
Proceeds from the sale of property and equipment	89	46
Net cash distributed as operator of oil and gas properties	(3,945)	(5,588)
Net cash received as operator of partnerships and joint ventures	467	340
Other	---	(48)
Net Cash Used in Investing Activities	(116,763)	(83,213)
Cash Flows from Financing Activities:		
Net proceeds from bank borrowings	32,600	---
Net proceeds from issuances of common stock	1,029	985
Purchase of treasury shares	(928)	---
Excess tax benefits from stock-based awards	---	550
Net Cash Provided by Financing Activities	32,701	1,535
Net Increase in Cash and Cash Equivalents	$ 1,905	$ 2,222
Cash and Cash Equivalents at Beginning of Period	1,058	53,005
Cash and Cash Equivalents at End of Period	$ 2,963	$ 55,227
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$ 4,507	$ 3,747
Cash paid during period for income taxes	$ 1,000	$ ---

See accompanying notes to condensed consolidated financial statements.

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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 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, 2006 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

Holding Company Structure

In December 2005, we implemented a holding company structure pursuant to Texas and federal law in a manner designed to be a non-taxable transaction. The new parent holding company assumed the Swift Energy Company name and continued to trade on the New York Stock Exchange. The purposes of this new holding company structure are to separate Swift Energy’s domestic and international operations to better reflect management practices, to improve our economics, and to provide greater administrative and organizational flexibility. Under the new organizational structure, four new subsidiaries were formed with the Texas parent holding company wholly owning three Delaware subsidiaries, which in turn wholly own Swift Energy's operating subsidiaries. Swift Energy Operating, LLC is the operator of record for Swift Energy's domestic properties. Swift Energy's name, charter, bylaws, officers, board of directors, authorized shares and shares outstanding remain substantially identical. The Company's international operations continue to be conducted through Swift Energy International, Inc. Swift Energy amended its bank credit agreement, debt indentures and various other plans and documents to accommodate the internal reorganization, but the Company's day-to-day conduct of business was not impacted. Accordingly, there was no impact on our financial position or results of operations.

Property and Equipment

We follow the “full-cost” method of accounting for oil and 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 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 three months ended March 31, 2007 and 2006, such internal costs capitalized totaled $8.5 million and $6.0 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the three months ended March 31, 2007 and 2006, capitalized interest on unproved properties totaled $2.5 million and $2.1 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and 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 gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization of oil and gas properties by the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, natural 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 gas produced during the period by the total estimated units of proved oil and 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, held 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 country-by-country 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, foreign currency exchange rates, the political stability in the countries in which we have an investment, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test.

At the end of each quarterly reporting period, the unamortized cost of oil and 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, 2007 consisted of natural gas price floors with strike prices lower than the period end prices and did not materially affect prices used in this calculation. This calculation is performed 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 gas that are ultimately recovered.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline 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 gas properties could occur in the future.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Swift Energy Company 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, as well as onshore oil and natural gas reserves in New

Zealand. Our undivided interests in natural gas processing plants are accounted for using the proportionate consolidation method, whereby our proportionate share of assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

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. Beginning in 2007, processing costs for natural gas and natural gas liquids (NGLs) that are paid in-kind are recorded in "Lease operating costs," prior to that these costs were deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its 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 balance sheet. 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, 2007, we did not have any material natural gas imbalances.

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 March 31, 2007 and December 31, 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.

Inventories

We value inventories at the lower of cost or market. Cost of crude oil inventory is determined using the weighted average method and all other inventory is accounted for using the first in, first out method ("FIFO"). The major categories of inventories, which are included in "Other current assets" on the accompanying balance sheets, are shown as follows:

(in thousands)	**Balance at March 31, 2007**	**Balance at December 31, 2006**
Materials, Supplies and Tubulars	$ 10,985	$ 10,611
Crude Oil	542	474
Total	$ 11,527	$ 11,085

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 underlying these financial statements include:

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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,

- accruals related to oil and 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, and
- estimates made in our income tax calculations.

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.

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 our deferred tax liability. This is also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. We do not expect to recognize significant increases or decreases in unrecognized tax benefits during the year ended December 31, 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2006 and March 31, 2007 no interest or penalties relating to income taxes have been recognized.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward remain subject to examination by tax authorities. Our Texas franchise tax returns for 2005 and prior years have been audited by the Texas State Comptroller. There are no unresolved items related to those audits. No other state returns are significant to our financial position. Our New Zealand income tax returns from 2002 forward remain subject to examination by the local tax authority.

Accounts Payable and Accrued Liabilities

Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at March 31, 2007 and December 31, 2006 are liabilities of approximately $29.6 million and $13.9 million, respectively, representing the amount by which checks issued, but not presented by vendors to the Company's banks for collection, exceeded balances in the applicable disbursement bank accounts.

Accumulated Other Comprehensive Income (Loss), Net of Income Tax

We follow the provisions of SFAS No. 130, “Reporting Comprehensive Income,” which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At March 31, 2007, we recorded $0.2 million, net of taxes of $0.1 million, of derivative losses in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying balance sheet. The components of accumulated other comprehensive Income (loss) and related tax effects were as follows:

(in thousands)	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive income at December 31,2006	$ 503	$ (187)	$ 316
Change in fair value of cash flow hedges	(1,092)	405	(687)
Effect of cash flow hedges settled during the period	250	(93)	157
Other comprehensive loss at March 31, 2007	$ (339)	$ 126	$ (214)

Total comprehensive income was $27.1 million and $37.8 million for the first quarter of 2007 and 2006, respectively.

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 gas prices, mainly through the purchase of price floors and collars. During the first quarters of 2007 and 2006, we recognized a net loss of $0.3 million and a net gain of $0.9 million; respectively, relating to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying statements of income. At March 31, 2007, the Company had recorded $0.2 million, net of taxes of $0.1 million, of derivative losses in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying 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 amount of ineffectiveness reported in “Price-risk management and other, net” for the first three months of 2007 and 2006 was not material. We expect to reclassify all amounts currently held in “Accumulated other comprehensive income (loss), net of income tax” into the statement of income within the next three months when the forecasted sale of hedged production occurs.

At March 31, 2007, we had in place price floors in effect for April 2007 through the June 2007 contract month for natural gas that cover a portion of our domestic natural gas production for April 2007 to June 2007. The natural gas price floors cover notional volumes of 1,800,000 Mmbtu with a weighted average floor price of $6.62 per Mmbtu. Our natural gas price floors in place at March 31, 2007 are expected to cover approximately 40% to 45% of our estimated domestic natural gas production from April 2007 to June 2007.

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 natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes-Merton option pricing model and is periodically verified against quotes from brokers. The fair value of these instruments at March 31, 2007, was less than $0.1 million and is recognized on the accompanying 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 are recorded as a reduction to general and administrative, net based on our estimate of the costs incurred to operate the wells. The total amount of supervision fees charged to the wells we operate was $2.6 million and $2.0 million in the first three months of 2007 and 2006, respectively.

Asset Retirement Obligation

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Asset Retirement Obligations." The 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 related asset 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 useful life 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 pool. 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. SFAS No. 143 was adopted by us effective January 1, 2003. The following provides a roll-forward of our asset retirement obligation:

(in thousands)	2007	2006
Asset Retirement Obligation recorded as of January 1	$ 34,460	$ 19,356
Accretion expense for the three months ended March 31	386	292
Liabilities incurred for new wells and facilities construction	140	174
Reductions due to sold, or plugged and abandoned wells	---	---
Increase (decrease) due to currency exchange rate fluctuations	11	(61)
Asset Retirement Obligation as of March 31	$ 34,997	$ 19,761

At both March 31, 2007 and December 31, 2006, approximately $0.9 million of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying balance sheets.

New Accounting Pronouncements

Effective January 1, 2007, the Company adopted FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109" ("FIN 48"). This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." See additional discussion of FIN 48 in the Income Taxes section of the footnotes. 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 our deferred tax liability.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this statement will have on its 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, 2006, for additional information related to these share-based compensation plans.

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants.

Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for both the three months ended March 31, 2007 and 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying condensed consolidated statements of operations.

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. In addition, 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. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our condensed consolidated statements of cash flows. 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 $0.3 and $0.6 million for the three months ended March 31, 2007 and 2006, respectively. The first quarter 2007 benefit has not been recognized in the financial statements as these benefits have not been realized since we are in a tax net operating loss position for the first quarter of 2007.

Net cash proceeds from the exercise of stock options were $0.4 million and $1.0 million for the three months ended March 31, 2007 and 2006. The actual income tax benefit realized from stock option exercises was $0.1 million and $0.3 million for the same periods.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in "General and Administrative, net" in the accompanying condensed consolidated statements of income, and was $2.3 million and $1.7 million for the quarters ended March 31, 2007 and 2006, 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 life 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,			
	2007		2006	
Dividend yield		0%		0%
Expected volatility		38.6%		39.5%
Risk-free interest rate		4.8%		4.8%
Expected life of options (in years)		6.5		6.3
Weighted-average grant-date fair value	$	20.56	$	21.02

The expected term has been 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, use a three-year period to estimate expected volatility of our stock option grants.

At March 31, 2007, there was $6.2 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 1.7 years. The following table represents stock option activity for the three months ended March 31, 2007:

	Shares	Wtd. Avg. Exer. Price	
Options outstanding, beginning of period	1,549,140	$	24.59
Options granted	182,500	$	43.48
Options canceled	---	$	---
Options exercised	(20,623)	$	19.80
Options outstanding, end of period	1,711,017	$	26.66
Options exercisable, end of period	931,452	$	23.11

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at March 31, 2007 was $27.4 million and 5.8 years and $17.7 million and 4.4 years, respectively. Total intrinsic value of options exercised during the three months ended March 31, 2007 was $0.5 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, 2006, 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, 2007, we had unrecognized compensation expense of approximately $23.8 million associated with these awards which are expected to be recognized over a weighted-average period of 2.3 years. The total fair value of shares vested during the first three months ended March 31, 2007 was $4.4 million.

The following table represents restricted stock activity for the three months ended March 31, 2007:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	503,184	$ 40.04
Restricted shares granted	282,250	$ 43.40
Restricted shares canceled	---	$ ---
Restricted shares vested	(100,248)	$ 38.77
Restricted shares outstanding, end of period	685,186	$ 41.61

(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 to employees using the treasury stock method. Certain of our stock options, that could potentially dilute Basic EPS in the future, were anti-dilutive for periods ended March 31, 2007 and 2006, 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, 2007 and 2006:

(in thousands, except per share data)	Three Months Ended March 31,					
	2007			2006		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 27,588	29,830	$ 0.92	$ 37,315	29,072	$ 1.28
Dilutive Securities:						
Restricted Stock	---	110		---	79	
Stock Options	---	556		---	846	
Diluted EPS:						
Net Income and Assumed Share Conversions						
Conversions	$ 27,588	30,497	$ 0.90	$ 37,315	29,996	$ 1.24

Options to purchase approximately 1.7 million shares at an average exercise price of $26.66 were outstanding at March 31, 2007, while options to purchase 2.2 million shares at an average exercise price of $22.87 were outstanding at March 31, 2006. Approximately 1.2 million and 1.3 million options to purchase shares were not included in the computation of Diluted EPS for the three months ended March 31, 2007 and 2006, respectively, because these options were anti-dilutive, in that the sum of the 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 575,216 shares and 248,849 shares were not included in the computation of Diluted EPS for the three months ended March 31, 2007 and 2006, respectively because these restricted stock grants were anti-dilutive 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, including the current portion, as of March 31, 2007 and December 31, 2006, was as follows:

(in thousands)	March 31, 2007	December 31, 2006
Bank Borrowings	$ 64,000	$ 31,400
7-5/8% senior notes due 2011	150,000	150,000
9-3/8% senior subordinated notes due 2012	200,000	200,000
Long-Term Debt	$ 414,000	$ 381,400

Bank Borrowings

At March 31, 2007, we had borrowings of $64.0 million under our $500.0 million credit facility with a syndicate of ten banks that had a borrowing base of $250.0 million and expires in October 2011. The interest rate is either (a) the lead bank's prime rate (8.25% at March 31, 2007) 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 October 2006, we increased, renewed, and extended this credit facility, increasing the facility to $500.0 million from $400.0 million, increasing the commitment amount under the borrowing base to $250.0 million from $150.0 million, and extending its expiration to October 3, 2011 from October 1, 2008. In April 2007, we increased the borrowing base to $350.0 million from $250.0 million.

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 gas properties. We have also pledged 65% of the stock in our two New Zealand subsidiaries as collateral for this credit facility. Under the terms of the 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. The borrowing base amount is re-determined at least every six months and the next scheduled borrowing base review is in November 2007.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.4 million and $0.2 million for the first quarters of 2007 and 2006, 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, 2007 and 2006.

Senior Notes Due 2011

These notes consist of $150.0 million of 7-5/8% senior notes due 2011, 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. In addition, prior to July 15, 2007, we may redeem up to 35% of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $3.9 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. 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, 2007 and 2006, respectively.

Senior Subordinated Notes Due 2012

These notes consist of $200.0 million of 9-3/8% senior subordinated notes due May 2012, which were issued on April 16, 2002, and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank credit facility and 7-5/8% senior notes. Interest on these notes is payable semiannually on May 1 and November 1, and commenced on November 1, 2002. On or after May 1, 2007, we may redeem these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.688% of principal, declining to 100% in 2010. Upon certain changes in control of Swift Energy, each holder of these notes will have the right to require us to repurchase 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 subordinated notes.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $4.8 million for each of the three month periods ended March 31, 2007 and 2006, respectively.

The aggregate maturities on our long-term debt are $214.0 million for 2011 and $200 million for 2012.

We have capitalized interest on our unproved properties in the amount of $2.5 million and $2.1 million for the three month periods ended March 31, 2007 and 2006, respectively.

(6) Foreign Activities

As of March 31, 2007, our gross capitalized oil and gas property costs in New Zealand totaled approximately $350.0 million. Approximately $335.9 million has been included in the "Proved properties" portion of our oil and gas properties, while $14.1 million is included as "Unproved properties." Our functional currency in New Zealand is the U.S. dollar. Net assets of our New Zealand operations total $257.6 million at March 31, 2007.

(7) Acquisitions and Dispositions

In October 2006, we acquired interests in five South Louisiana fields. The property interests are located in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. We paid approximately $167.9 million in cash for these interests. After taking into account internal acquisition costs of $4.0 million, our total cost was $171.9 million. We allocated $154.6 million of the acquisition price to "Proved Properties," $28.8 million to "Unproved Properties," and recorded a liability for $11.5 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 Louisiana. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward.

In December 2006, we acquired additional interests in our Lake Washington field. We paid approximately $20.0 million in cash for these interests. After taking into account internal acquisition costs of $0.4 million, our total cost was $20.4 million. We allocated $18.7 million of the acquisition price to “Proved Properties,” $2.5 million to “Unproved Properties,” and recorded a liability for $0.8 million to “Asset retirement obligation” on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from this acquisition have been included in our accompanying consolidated statements of income from the date of acquisition forward.

(8) Condensed Consolidating Financial Information

In December 2005, we amended the indenture for our 9-3/8% Senior Subordinated Notes due 2012 and our 7-5/8% Senior Notes due 2011 to reflect our new holding company organizational structure (as discussed in Note 2). Pursuant to the amendment, both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) became co-obligors of these senior notes and senior subordinated debt. The co-obligations are full and unconditional and are joint and several. Prior to amendment, Swift Energy Company was the sole obligor. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and significant subsidiaries:

Condensed Consolidating Balance Sheets

(in thousands)	March 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	$ ---	$ 76,287	$ 18,641	$ ---	$ 94,928
Property and equipment	---	1,297,606	238,675	---	1,536,281
Investment in subsidiaries (equity method)	828,961	---	620,621	(1,449,582)	---
Other assets	---	42,831	714	(34,060)	9,485
Total assets	$ 828,961	$ 1,416,724	$ 878,651	$ (1,483,642)	$ 1,640,694
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ ---	$ 118,829	$ 3,757	$ ---	$ 122,586
Long-term liabilities	---	677,274	45,933	(34,060)	689,147
Stockholders' equity	828,961	620,621	828,961	(1,449,582)	828,961
Total liabilities and stockholders' equity	$ 828,961	$ 1,416,724	$ 878,651	$ (1,483,642)	$ 1,640,694

(in thousands)	December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
ASSETS					
Current assets	$ ---	$ 75,270	$ 17,303	$ ---	$ 92,573

Property and equipment		---		1,239,722		243,590		---		1,483,312
Investment in subsidiaries (equity method)		797,917		---		590,720		(1,388,637)		---
Other assets		---		42,519		705		(33,427)		9,797
Total assets	$	797,917	$	1,357,511	$	852,318	$	(1,422,064)	$	1,585,682
LIABILITIES AND STOCKHOLDERS' EQUITY										
Current liabilities	$	---	$	137,016	$	8,959	$	---	$	145,975
Long-term liabilities		---		629,775		45,442		(33,427)		641,789
Stockholders' equity		797,917		590,720		797,917		(1,388,637)		797,917
Total liabilities and stockholders' equity	$	797,917	$	1,357,511	$	852,318	$	(1,422,064)	$	1,585,682

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Condensed Consolidating Statements of Income

(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	$ 11,014	$ ---	$ 141,093
Expenses	---	88,162	10,198	---	98,360
Income (loss) before the following:	---	41,917	816	---	42,734
Equity in net earnings of subsidiaries	27,588	---	26,446	(54,034)	---
Income before income taxes	27,588	41,917	27,262	(54,034)	42,734
Income tax provision (benefit)	---	15,472	(327)	---	15,145
Net income	$ 27,588	$ 26,445	$ 27,588	$ (54,034)	$ 27,588

(in thousands)	Three Months Ended March 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	**Swift Energy Operating, LLC (Co-obligor)**	**Other Subsidiaries**	**Eliminations**	**Swift Energy Co. Consolidated**
Revenues	$ ---	$ 119,438	$ 16,731	$ ---	$ 136,169
Expenses	---	65,798	12,596	---	78,394
Income (loss) before the following:	---	53,640	4,135	---	57,775
Equity in net earnings of subsidiaries	37,315	---	33,828	(71,143)	---
Income before income taxes	37,315	53,640	37,963	(71,143)	57,775
Income tax provision (benefit)	---	19,812	648	---	20,460
Net income	$ 37,315	$ 33,828	$ 37,315	$ (71,143)	$ 37,315

Condensed Consolidating Statements of Cash Flows

(in thousands)	Three Months Ended March 31, 2007				
				Eliminations	

	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries		Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 78,574	$ 7,392	$ ---	$ 85,966
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	$ ---	$ 858	$ 1,046	$ ---	$ 1,904
Cash, beginning of period	---	50	1,008	---	1,058
Cash, end of period	$ ---	$ 908	$ 2,054	$ ---	$ 2,963

(in thousands)	Three Months Ended March 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 76,061	$ 7,839	$ ---	$ 83,900
Cash flow from investing activities	---	(71,734)	(13,637)	2,157	(83,213)
Cash flow from financing activities	---	1,535	2,157	(2,157)	1,535
Net increase in cash	$ ---	$ 5,862	$ (3,640)	$ ---	$ 2,223
Cash, beginning of period	---	44,911	8,094	---	53,005
Cash, end of period	$ ---	$ 50,773	$ 4,454	$ ---	$ 55,227

(9) Segment Information

The Company has two reportable segments, one domestic and one foreign, both of which are in the business of oil and natural gas exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate our performance based on profit or loss from oil and gas operations before price-risk management and other, net, general and administrative, net, and interest expense, net. Our reportable segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	Three Months Ended March 31,					
	2007			2006		
	Domestic	New Zealand	Total	Domestic	New Zealand	Total
Oil and gas sales	$ 130,222	$ 10,807	$ 141,029	$ 118,085	$ 16,868	$ 134,953
Costs and Expenses:						
Depreciation, depletion and amortization	41,722	5,925	47,647	28,022	7,385	35,406
Accretion of asset retirement obligation	341	45	386	256	36	292
Lease operating costs	15,714	2,590	18,304	11,308	3,087	14,394
Severance and other taxes	16,050	697	16,748	13,608	1,146	14,754
Income from oil and gas operations	$ 56,395	$ 1,549	$ 57,945	$ 64,892	$ 5,215	$ 70,107
Price-risk management and other, net			64			1,216
General and administrative, net			8,529			7,687
Interest expense, net			6,746			5,861
Income Before Income Taxes			$ 42,734			$ 57,775
Total Assets	$ 1,408,781	$ 231,913	$ 1,640,694	$ 1,052,793	$ 252,112	$ 1,304,905

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, 2006. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Statements" on page 31 of this report.

Overview

In the first quarter of 2007 as compared to the same period in 2006, our revenues increased 4% to $141.1 million and our total costs increased 25% to $98.4 million, resulting in net income of $27.6 million, a 26% decrease. Our revenue increase is attributable to our increased levels of domestic production, offset by lower commodity prices and decreased production in New Zealand. Our production increased 6% to 17.5 Bcfe for the first quarter of 2007 as compared to first quarter 2006, due to our continued drilling success in our South Louisiana region along with production from the five new fields we acquired in that region in October 2006. Production decreased 6% from our production in the fourth quarter of 2006, due primarily to both natural production declines and maintenance in New Zealand as well as maintenance and repairs in the Lake Washington field. First quarter 2007 production included domestic production of 15.2 Bcfe, a 19% increase, and 2.3 Bcfe produced in New Zealand, a 40% decrease, in both cases when compared to production in the same period in 2006.

For the first quarter of 2007, we saw reduced commodity prices for the first time in several quarters. Costs have been building in the industry over the past two years and during the first quarter of 2007, industry-wide costs began outpacing commodity prices. We expect industry-wide costs to moderate over the remainder of 2007 and we will continue to focus on capital efficiency by managing our costs and expenses to align with the current commodity prices. The largest increase in our costs and expenses was due to increased depreciation, depletion and amortization expense, not only due to our larger depletable property base and higher production, but also due to increases in future development costs that reflect industry inflation.

Our financial position remains strong. Our debt to capitalization ratio was 33% at March 31, 2007, compared to 32% at year-end 2006, as debt levels increased in 2007 and retained earnings increased as a result of the current period profit. Our debt to PV-10 ratio decreased to 13% at March 31, 2007 compared to 14% at December 31, 2006, primarily due to higher oil, NGL and natural gas prices at March 31, 2007 which increased our PV-10 value, partially offset by an increase in our total debt.

We are maintaining our original 2007 capital expenditure budget of $350 million to $400 million, net of minor non-core dispositions and excluding any property acquisitions. This spending is within our expected cash flow. We have the opportunity set to spend more capital on growth projects, but we are holding the line on spending until we get a better understanding of trends for commodity pricing and costs. We continue to reserve a portion of our capital budget for discretionary spending, which we will spend only upon realization of operational success and supporting commodity prices. For 2007, we are still targeting total production to increase 7% to 10% and proved reserves to increase 4% to 6% over 2006 levels.

We have begun 2007 with another exciting exploration discovery in our South Louisiana region. The Faria prospect tested over 17 MMcfe/d from two zones in the Bay de Chene field and is another success achieved through our technology led strategy. We have built an expansive exploration inventory that we will exploit throughout the remainder of the year and over the next several years. Our principal goal for 2007 is to continue the Swift Energy legacy of growth by meeting our production and reserves targets. Our performance in the first quarter of 2007 puts us on the path for another great year in 2007.

Results of Operations – Three Months Ended March 31, 2007 and 2006

Revenues. Our revenues in the first quarter of 2007 increased by 4% compared to revenues in the same period in 2006, due primarily to an increase in production principally from our Lake Washington, Cote Blanche Island, and Bay De Chene fields, along with production from properties acquired during the fourth quarter of 2006. These production gains were partially offset by lower oil and natural gas prices. Revenues from our oil and gas sales comprised substantially all of net revenues for the first quarter of 2007 and 2006. In the first quarter of 2007, oil production made up 63% of total production, natural gas made up 31%, and NGL represented 6%. In the first quarter of 2006, oil production made up 58% of total production, natural gas made up 36%, and NGL represented 6%. The percentage of our total production from oil increased as production in South Louisiana fields, which are predominantly oil, increased over first quarter of 2006 levels.

Our first quarter 2007 weighted average prices decreased 1% to $8.05 per Mcfe from $8.14 in the first quarter of 2006, with oil prices decreasing 5% to $58.07 from $60.83, natural gas prices decreasing 4% to $5.14 from $5.38, and NGL prices rising 20% to $36.48 from $30.34.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes for the periods ended March 31, 2007 and 2006:

Regions	Three Months Ended March 31, Oil and Gas Sales (In Millions) 2007	2006	Net Oil and Gas Sales Volumes (Bcfe) 2007	2006
South Texas	$ 12.5	$ 18.4	1.9	2.3
Toledo Bend	7.7	9.2	1.1	1.2
South Louisiana	109.0	88.8	12.1	9.1
Other	1.0	1.7	0.1	0.2
Total Domestic	$ 130.2	$ 118.1	15.2	12.8
New Zealand	10.8	16.9	2.3	3.8
Total	$ 141.0	$ 135.0	17.5	16.6

The following table provides additional information regarding our quarterly oil and gas sales:

	Sales Volume Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Average Sales Price Oil (Bbl)	NGL (Bbl)	Gas (Mcf)
2007							
Three Months Ended March 31:							
Domestic	1,774	133	3.8	15.2	$ 57.87	$ 39.90	$ 5.92
New Zealand	62	48	1.6	2.3	$ 64.01	$ 26.96	$ 3.36
Total	1,836	180	5.4	17.5	$ 58.07	$ 36.48	$ 5.14
2006							
Three Months Ended March 31:							
Domestic	1,487	90	3.3	12.8	$ 60.56	$ 39.75	$ 7.42
New Zealand	124	62	2.7	3.8	$ 64.13	$ 16.68	$ 2.91
Total	1,611	152	6.0	16.6	$ 60.83	$ 30.34	$ 5.38

In the first quarter of 2007, our $6.1 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $5.3 million unfavorable impact on sales, of which $5.1 million was attributable to the 5% decrease in average oil prices received, and $1.3 million of decreases attributable to the 4% decrease in average gas prices received, offset by $1.1 million of increases attributable to the 20% increase in average NGL prices received; and

- Volume variances that had a $11.3 million favorable impact on sales, with $13.7 million of increases coming from the 225,000 Bbl increase in oil sales volumes, $0.8 million of increases attributable to the 28,000 Bbl increase in NGL sales volumes, offset by $3.2 million of decreases due to the 0.6 Bcf decrease in gas sales volumes.

Costs and Expenses. Our expenses in the first quarter of 2007 increased $20.0 million, or 25%, compared to expenses in the same period of 2006. The increase was due to a $12.2 million increase in DD&A as our production and depletable oil and gas property base increased, a $3.9 million increase in lease operating expenses due to higher production and increased insurance premiums, and a $2.0 million increase in severance and other taxes due to increased domestic production volumes in the first quarter of 2007.

Our first quarter 2007 general and administrative expenses, net, increased $0.8 million, or 11%, from the level of such expenses in the same 2006 period. This increase was primarily due to an expansion of our workforce and an increase in stock compensation expense. Our stock compensation expense recorded in general and administrative, net, increased by $0.6 million, net of capitalized amounts, over first quarter of 2006 levels. For the first quarters of 2007 and 2006, our capitalized general and administrative costs, including capitalized stock compensation, totaled $8.5 million and $6.0 million, respectively. Our capitalized general and administrative expenses increased due to the expansion of our workforce and the capitalization of stock compensation related to the geological and geophysical workforce. Our net general and administrative expenses per Mcfe produced were $0.49 per Mcfe in the first quarter 2007 and $0.46 per Mcfe in the first quarter of 2006. The portion of supervision fees recorded as a reduction to general and administrative expenses was $2.6 million for the first quarter of 2007 and $2.0 million for the 2006 period.

DD&A increased $12.2 million, or 35%, in the first quarter of 2007 from the level of those expenses in the same period of 2006. Domestically, DD&A increased $13.7 million in the first quarter of 2007 due to increases in the depletable oil and gas property base, including future development costs and higher production in the 2007 period. In New Zealand, DD&A decreased by $1.5 million in the first quarter of 2007 due to lower production during the 2007 period, partially offset by increases in the depletable oil and gas property base and lower reserves volumes. Our DD&A rate per Mcfe of production was $2.72 and $2.13 in the first quarters of 2007 and 2006, respectively.

We recorded $0.4 million and $0.3 million of accretions to our asset retirement obligation in the first quarters of 2007 and 2006.

Our lease operating costs in the first quarter of 2007 increased $3.9 million, or 27%, over the level of such expenses in the same 2006 period. All of the increase was related to our domestic operations, which increased primarily due to higher production from our South Louisiana area, including costs from properties acquired in 2006, and higher insurance costs. Our lease operating costs in New Zealand decreased in the first quarter of 2007 by $0.5 million due to lower production. Our lease operating costs per Mcfe produced were $1.05 in the first quarter of 2007 and $0.87 in the first quarter of 2006.

In the first quarter of 2007, severance and other taxes increased $2.0 million, or 14%, over levels in the first quarter of 2006. The increase was due primarily to higher production in South Louisiana, offset partially by lower commodity prices. 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 increases, the overall percentage of severance costs to sales also increases. Severance and

other taxes, as a percentage of oil and gas sales, were approximately 11.9% and 10.9% in the first quarters of 2007 and 2006, respectively.

Our total interest cost in the first quarter of 2007 was $9.3 million, of which $2.5 million was capitalized. Our total interest cost in the first quarter of 2006 was $8.0 million, of which $2.1 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase of interest expense in the first quarter of 2007 was primarily attributable to increased borrowings against our line of credit, offset partially by higher capitalized costs. The increase in borrowings was primarily due to our fourth quarter 2006 property acquisitions.

Our overall effective tax rate was 35.4% in the first quarters of 2007 and 2006. The effective income tax rate for both periods was higher than the U.S. statutory rate primarily due to state income taxes, and was partially offset by reductions attributable to the currency effect on the New Zealand operations.

Net Income. For the first quarter of 2007, our net income of $27.6 million was 26% lower, and Basic EPS of $0.92 was 28% lower, than our first quarter of 2006 net income of $37.3 million and Basic EPS of $1.28. Our Diluted EPS in the first quarter of 2007 of $0.90 was 27% lower than our first quarter 2006 Diluted EPS of $1.24. These lower amounts are due to an increase in costs that exceeded the increase in oil and gas revenues during the first quarter of 2007.

Share-Based Compensation

Effective January 1, 2006, the Company adopted SFAS No. 123R, “Share-Based Payment” utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with APB No. 25, “Accounting for Stock Issued to Employees” (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants. The adoption of SFAS No. 123R will increase our compensation expense related to employee stock option grants over pre-implementation period levels.

Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized in both the three months ended March 31, 2007 and 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in “General and Administrative, net” in the accompanying condensed consolidated statements of operations.

We continue to use the Black-Scholes-Merton option pricing model to estimate the fair value of stock-option awards with the following weighted-average assumptions for the indicated periods:

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Dividend yield	0%	0%
Expected volatility	38.6%	39.5%
Risk-free interest rate	4.8%	4.8%
Expected life of options (in years)	6.5	6.3
Weighted-average grant-date fair value	$ 20.56	$ 21.02

The expected term has been 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 analysis of all relevant factors use a three-year period to estimate expected volatility of our stock option grants. 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 life of the award.

At March 31, 2007, there was $6.2 million of unrecognized compensation cost related to stock options, which are expected to be recognized over a weighted-average period of 1.7 years, and unrecognized compensation expense of $23.8 million related to restricted stock awards which are expected to be recognized over a weighted-average period of 2.3 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, 2006 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, 2006.

Internal Control over Financial Reporting

Effective April 1, 2007, we began using a new commercial information system. This system integrates our accounting processes from production of oil and gas to receipt of cash and from procurement of products and services to payment for such costs. It also further automates our financial reporting processes. We anticipate a positive impact on our internal control over financial reporting for periods beginning with the second quarter of 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 declined in the first quarter of 2007 from levels earlier in 2006; however, it is currently significantly higher 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 wide fluctuations in the price of oil. Domestic natural gas prices continue to remain higher when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Income Tax Regulations

The tax laws in the jurisdictions in which we operate continuously change and professional judgments regarding such tax laws can differ.

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 our deferred tax liability. This is also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. We do not expect to recognize significant increases or decreases in unrecognized tax benefits during the year ended December 31, 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2006 and March 31, 2007 no interest or penalties relating to income taxes have been recognized.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward remain subject to examination by tax authorities. Our Texas franchise tax returns for 2005 and prior years have been audited by the Texas State Comptroller. There are no unresolved items related to those audits. No other state returns are significant to our financial position. Our New Zealand income tax returns from 2002 forward remain subject to examination by the local tax authority.

Liquidity and Capital Resources

During the first quarter of 2007, we relied upon our net cash provided by operating activities of $86.0 million and bank borrowings of $32.6 million to fund capital expenditures of $113.4 million. During the first quarter of 2006, we relied upon our net cash provided by operating activities of $83.9 million to fund capital expenditures of $78.0 million.

Acquisitions. In October 2006, we acquired interests in five South Louisiana fields from BP America Production Company. The total price for these interests was approximately $168 million. The property interests are located primarily in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. In addition, we have acquired virtually all of the remaining outstanding interest in the South Bearhead Creek field, located in Beauregard Parish, Louisiana, for $4.5 million in November 2006.

Net Cash Provided by Operating Activities. For the first quarter of 2007, our net cash provided by operating activities was $86.0 million, representing a 2% increase as compared to $83.9 million generated during the same 2006 period. The $2.1 million increase in the first quarter of 2007 was primarily due to a reduction in accounts receivable, along with adding back increased DD&A, somewhat offset by an decrease in accounts payable and accrue liabilities in the current quarter.

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 March 31, 2007 and December 31, 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 Bank Credit Facility. We had borrowings of $64.0 million and $31.4 million under our bank credit facility at March 31, 2007 and December 31, 2006. Our bank credit facility consists of a $500.0 million revolving line of credit with a $350.0 million borrowing base. The borrowing base is re-determined at least every six months and the next scheduled review is 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. 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 our operations, financial condition, prospects or properties, and would impair our 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 $64.0 million at March 31, 2007, extends until October 3, 2011. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $200.0 million of 9-3/8% senior subordinated notes mature May 1, 2012.

On or after May 1, 2007, we are entitled to redeem our $200.0 million 9-3/8% senior subordinated notes at a redemption price, plus accrued and unpaid interest, of 104.688% of principal. If these notes were redeemed, we would most likely use a combination of drawings upon our credit facility, cash flows from operations, and the use of debt and/or equity offerings to fund any such redemption.

Working Capital. Our working capital improved from a deficit of $53.4 million at December 31, 2006, to a deficit of $27.7 million at March 31, 2007. The improvement primarily resulted from a decrease in accrued capital costs due to a decrease in our drilling and facility construction activities from year-end 2006 levels, along with a decrease in accounts payable and accrued liabilities.

Capital Expenditures. In the first quarter of 2007, we relied upon our net cash provided by operating activities of $86.0 million and bank borrowings of $32.6 million to fund capital expenditures of $113.4 million. Our total capital expenditures of approximately $113.4 million in the first quarter of 2007 included:

Domestic expenditures of $109.8 million as follows:

- $57.6 million for drilling and developmental activity costs, predominantly in our South Louisiana area;
- $25.4 million of domestic prospect costs, principally related to seismic activities, prospect leasehold, and geological costs of unproved prospects;
- $22.7 million for exploratory drilling;
- $2.4 million primarily for leasehold improvements in our Houston office, software, computer equipment, vehicles, furniture, and fixtures;
- $1.7 million for acquisitions of properties.

New Zealand expenditures of $3.6 million as follows:

- $3.1 million for developmental activity, and gas processing plant costs;
- $0.3 million on prospect costs and geological costs of unproved properties;
- $0.2 million for exploratory activities;
- and less than $0.1 million for computer equipment, software, furniture, and fixtures.

We successfully completed 14 of 16 domestic wells in the first quarter of 2007, for a success rate of 88%. A total of 12 wells were drilled in the Lake Washington area, of which 10 were completed, and 2 wells were drilled and completed in the South Bearhead Creek area. One well was also drilled successfully in the AWP Olmos area. In New Zealand, we did not spud any wells during the first quarter of 2007.

Our current 2007 capital expenditure budget is $350 million to $400 million, net of minor non-core dispositions and excluding any property acquisitions. Approximately 95% of the budget is targeted for domestic activities, predominantly in our South Louisiana region, with about 5% planned for activities in the New Zealand region. For 2007, we are targeting total production to increase 7% to 10% and proved reserves to increase 4% to 6% over 2006 levels. We may also increase our capital expenditure budget if commodity prices rise during the year or if strategic opportunities warrant. If 2007 capital expenditures exceed our cash flow from operating activities, we can fund these expenditures with our credit facility to fund these expenditures.

For the last nine months of 2007, we expect to make capital expenditures of approximately $235 to $285 million. Capital expenditures for 2006 were $557.5 million.

During the last nine months of 2007, we anticipate drilling or participating in the drilling of up to an additional 20 to 24 wells in the South Louisiana region, an additional 10 to 13 wells in the AWP Olmos area, and several additional wells, with varying working interest percentages, mainly in the Toledo Bend region. In addition, we plan on drilling up to two wells in New Zealand.

Our 2007 capital expenditures continue to be focused on developing and producing long-lived reserves in South Louisiana, South Texas, and Toledo Bend regions., along with property acquisitions and an expansion of our Lake Washington facilities. We expect our 2007 total production to increase over 2006 levels, primarily from our South Louisiana area. Our production in the South Texas region is expected to remain relatively flat. We expect production in our other regions to decrease as a limited amount of new drilling is currently budgeted to offset the natural production decline of these regions.

New Accounting Pronouncements

Effective January 1, 2007, the Company adopted FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109" ("FIN 48"). This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, “Accounting for Income Taxes.” See additional discussion of FIN 48 in the Income Taxes section of the footnotes. 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 our deferred tax liability.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this statement will have on its 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 and 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, 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 that convey the uncertainty of 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. Among the factors that could cause actual results to differ materially are the uncertainty of finding, replacing, developing or acquiring reserves; fluctuations in crude oil, natural gas and natural gas liquids prices or demand; adequate availability of skilled personnel, services and supplies; the uncertainty of drilling results; potential failure or delays in achieving reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance; requirements for 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 herein, and set forth from time to time in our other public reports, filings and public statements. Also, because of the volatility in oil and gas prices and other factors, interim results are not necessarily indicative of those for a full year.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Commodity Risk

Our major market risk exposure is the volatile 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 derivative instruments (such as futures, forward contracts, swaps, and option contracts such as floors and collars) to mitigate price risk associated with fluctuations in oil and natural gas prices. Below is a description of the derivative instruments we have utilized to hedge our exposure to price risk.

- Price Floors – At March 31, 2007, we had in place price floors in effect through the June 2007 contract month for natural gas, which are expected to cover approximately 40% to 45% of our domestic natural gas production for April 2007 through June 2007. The natural gas floors cover notional volumes of 1,800,000 Mmbtu, and expire at various dates from April 2007 to June 2007, with a weighted average floor price of $6.62 per Mmbtu.

- New Zealand Gas Contracts – All of our current gas production in New Zealand is sold under fixed-price contracts denominated in New Zealand dollars. These contracts protect against price volatility, and our revenue from these contracts will vary only due to production fluctuations and foreign exchange rates.

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 that the loss of any single oil or gas customer would have a material adverse effect on our financial position or 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 obligations, all denominated in New Zealand dollars. We use the U.S. dollar as our functional currency in New Zealand and because of this, our results of operations, cash flows and effective tax rate are impacted from fluctuations between the U.S. dollar and the New Zealand dollar.

Interest Rate Risk

Our Senior Notes due 2011 and Senior Subordinated Notes due 2012 have fixed interest rates; consequently we are not exposed to cash flow risk from market interest rate changes on these notes. However, there is a risk that market rates will decline and the required interest payments on our Senior Notes and Senior Subordinated Notes may exceed those payments based on the current market rate. At March 31, 2007, we had borrowings of $64.0 million under our credit facility, which is subject to floating rates and therefore susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 83 basis points and would not have a material adverse effect on our 2007 cash flows based on this same level or a modest 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 2007 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 2006 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 2007:

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)
01/01/07 - 01/31/07 (1)	17,407	$ 44.77	---	---
02/01/07 - 02/28/07 (1)	3,487	42.62	---	---
03/01/07 - 03/31/07	---	---	---	---
Total	20,894	$ 44.41	---	$ ---

(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.
99.1*	Amendment No. 2 to the Swift Energy Company 2005 Stock Compensation Plan

* 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 4, 2007	By:	/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date: May 4, 2007	By:	/s/ David W. Wesson. David W. Wesson Controller and Principal Accounting Officer