SWIFT ENERGY CO
Form 10-Q
May 05, 2006

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, 2006

Commission File Number 1-8754

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

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

16825 Northchase Drive, Suite 400	
Houston, Texas	77060
(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 X No

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 x Accelerated filer Non-accelerated filer

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

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

Common Stock	29,133,803 Shares
($.01 Par Value)	(Outstanding at April 30, 2006)
(Class of Stock)	

1

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2006

INDEX

2

Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries

	March 31, 2006	De
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 55,227,167	$
Accounts receivable-		
Oil and gas sales	51,633,643	
Joint interest owners	4,765,417	
Other Receivables	9,850,320	
Deferred tax asset	22,130,793	
Other current assets	18,578,260	
Total Current Assets	162,185,600	
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	1,802,196,935	
Unproved properties	100,954,114	
	1,903,151,049	
Furniture, fixtures, and other equipment	20,673,961	
	1,923,825,010	
Less - Accumulated depreciation, depletion, and amortization	(791,057,946)	
	1,132,767,064	
Other Assets:		
Debt issuance costs	7,733,329	
Restricted assets	2,219,173	
	9,952,502	
	$ 1,304,905,166	$
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 50,549,403	$
Accrued capital costs	47,893,579	
Accrued interest	10,333,272	
Undistributed oil and gas revenues	4,320,520	
Total Current Liabilities	113,096,774	

Long-Term Debt	350,000,000
Deferred Income Taxes	171,170,929
Asset Retirement Obligation	19,500,324
Lease Incentive Obligation	975,212
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, 29,541,526 and 29,458,974 shares issued, and 29,114,440 and 29,009,530 shares outstanding, respectively	295,415
Additional paid-in capital	363,945,910
Treasury stock held, at cost, 427,086 and 449,444 shares, respectively	(6,124,944)
Unearned compensation	---
Retained earnings	291,617,263
Accumulated other comprehensive income (loss), net of income tax	428,283
	650,161,927
	$ 1,304,905,166

See accompanying notes to condensed consolidated financial statements.

Condensed Consolidated Statements of Income
Swift Energy Company and Subsidiaries

	Three Months Ended March 31, 2006	2005
Revenues:		
Oil and gas sales	$ 134,952,993	$ 95,521,333
Price-risk management and other, net	1,215,938	99,351
	136,168,931	95,620,684
Costs and Expenses:		
General and administrative, net	7,686,909	4,874,308
Depreciation, depletion, and amortization	35,406,497	24,205,378
Accretion of asset retirement obligation	291,515	186,507
Lease operating cost	14,394,489	11,048,782
Severance and other taxes	14,753,606	9,203,081
Interest expense, net	5,860,919	6,344,009
	78,393,935	55,862,065

Income Before Income Taxes	57,774,996	39,758,619
Provision for Income Taxes	20,460,490	14,069,467
Net Income	$ 37,314,506	$ 25,689,152
Per Share Amounts-		
Basic: Net Income	$ 1.28	$ 0.91
Diluted: Net Income	$ 1.24	$ 0.89
Weighted Average Shares Outstanding	29,071,764	28,160,949

See accompanying notes to condensed consolidated financial statements.

Condensed Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries

	Common Stock(1)	Additional Paid-In Capital	Treasury Stock	Unearned Compensation	Retained Earnings
Balance, December 31, 2004	$ 285,706	$ 343,536,298	$ (6,896,245)	$ (1,728,585)	$138,524,3
Stock issued for benefit plans(31,424 shares)	---	435,134	450,659	---	-
Stock options exercised (840,847 shares)	8,409	9,804,555	---	---	-
Tax benefits from exercise of stock options	---	4,366,236	---	---	-
Employee stock purchase plan (32,495 shares)	325	642,354	---	---	-
Issuance of restricted stock (15,000 shares)	150	---	---	---	-
Grants of restricted stock (158,500 shares)	---	6,668,608	---	(6,072,008)	-
Forfeitures of restricted stock	---	(367,490)	---	367,490	-
Amortization of restricted stock compensation	---	---	---	1,583,283	-

Comprehensive Income:					
Net income	---	---	---	---	115,778,4
Other Comprehensive Income	---	---	---	---	-
Total Comprehensive Income	---	---	---	---	-
Balance, December 31, 2005	$ 294,590	$ 365,085,695	$ (6,445,586)	$ (5,849,820)	$254,302,7
Stock issued for benefit plans (22,358 shares)	---	714,049	320,642	---	-
Stock options exercised (68,372 shares)	683	984,297	---	---	-
Adoption of SFAS No. 123R	---	(5,875,280)	---	5,849,820	-
Excess tax benefits from stock-based awards	---	550,218	---	---	-
Issuance of restricted stock (14,180 shares)	142	(142)	---	---	-
Amortization of stock compensation	---	2,487,073	---	---	-
Comprehensive Income:					
Net income	---	---	---	---	37,314,5
Other Comprehensive Income	---	---	---	---	-
Total Comprehensive Income	---	---	---	---	-
Balance, March 31, 2006	$ 295,415	$ 363,945,910	$ (6,124,944)	$ ---	$291,617,2

(1) $.01 Par Value

See accompanying notes to condensed consolidated financial statements.

Condensed Consolidated Statements of Cash Flows
Swift Energy Company and Subsidiaries

Three Months Ended March 31,

	2006	2005
Cash Flows from Operating Activities:		
Net income	$ 37,314,506	$ 25,689,
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	35,406,497	24,205,
Accretion of asset retirement obligation	291,515	186,
Deferred income taxes	19,992,384	14,069,
Stock-based compensation expense	1,710,417	95,
Other	(3,120,456)	889,
Change in assets and liabilities-		
Increase in accounts receivable	(9,798,613)	(18,
Decrease in accounts payable and accrued liabilities	(189,060)	(1,603,
Increase in income taxes payable	468,106	
Increase in accrued interest	1,825,076	1,137,
Net Cash Provided by Operating Activities	83,900,372	64,651,
Cash Flows from Investing Activities:		
Additions to property and equipment	(77,963,107)	(44,526,
Proceeds from the sale of property and equipment	45,962	121,
Net cash distributed as operator of oil and gas properties	(5,587,868)	(7,913,
Net cash received (distributed) as operator of partnerships and joint ventures	339,655	(884,
Other	(47,607)	4,
Net Cash Used in Investing Activities	(83,212,965)	(53,198,
Cash Flows from Financing Activities:		
Payments of bank borrowings	---	(7,500,0
Net proceeds from issuances of common stock	984,980	841,
Excess tax benefits from stock-based awards	550,218	
Net Cash Provided by (Used in)Financing Activities	1,535,198	(6,658,
Net Increase in Cash and Cash Equivalents	$ 2,222,605	$ 4,794,
Cash and Cash Equivalents at Beginning of Period	53,004,562	4,920,
Cash and Cash Equivalents at End of Period	$ 55,227,167	$ 9,714,
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$ 3,747,050	$ 4,923,
Cash paid during period for income taxes	$ ---	$

See accompanying notes to condensed consolidated financial statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(1) General Information

The condensed consolidated financial statements included herein have been prepared by Swift Energy Company and reflect necessary adjustments, all of which were of a recurring nature, 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 the latest Annual Report on Form 10-K 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 its common stock and continued to trade on the New York and Pacific Stock Exchanges. 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, 2006 and 2005, such internal costs capitalized totaled $6.0 million and $4.1 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the three months ended March 31, 2006 and 2005, capitalized interest on unproved properties totaled $2.1 million, and $1.8 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, 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 three and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical (G&G) costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a 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 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, 2006 consisted of natural gas and crude oil price floors with strike prices higher than the period end price but did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization ("DD&A") is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and 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 gas processing plants, and investments in oil and gas limited partnerships where we are the general partner are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying 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. Processing costs for natural gas and natural gas liquids (NGLs) that are paid in-kind are 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, 2006, 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, 2006 and December 31, 2005, 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. Receivables related to insurance reimbursement are computed in accordance with applicable accounting guidance; and we monitor our costs incurred and their collectibility under our insurance policies and believe all amounts recorded are recoverable.

Inventories

We value inventories at the lower of cost or market value. 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:

	Balance at March 31, 2006 (000's)	Balance at December 31,2005 (000's)
Materials, Supplies and Tubulars...	$ 12,428	$ 8,494
Crude Oil	772	916
Total	$ 13,200	$ 9,410

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

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:

- 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 of stock compensation expense,
- 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 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. The effective tax rate for the three months ended March 31, 2006 and 2005 was higher than the U.S. Federal statutory tax rate primarily due to state income taxes, partially offset by reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. As of March 31, 2006, we believe we will utilize all of our domestic operating loss carryforwards during the 2006 tax year, and these amounts are classified as current in the "Deferred tax asset" account on the accompanying balance sheet.

Accounts Payable and Accrued Liabilities

Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at March 31, 2006 and December 31, 2005 are liabilities of approximately $12.1 million and $9.9 million, respectively, representing the amount by which checks issued, but not presented 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, 2006, we recorded $0.4 million, net of taxes of $0.2 million, of derivative gains 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 for 2006 were as follows:

	Gross Value	Tax Effect
Other comprehensive income at December 31, 2005	$ (110,094)	$ 40,625
Change in fair value of cash flow hedges	(104,721)	38,642
Effect of cash flow hedges settled during the period	889,687	(325,856)
Other comprehensive income at March 31, 2006	$ 674,872	$ (246,589)

Total comprehensive income was $37.8 million and $24.7 million for the first quarter of 2006 and 2005, 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 quarter of 2006 and 2005, we recognized a net gain of $0.9 million and a net loss of $0.1 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, 2006, the Company had recorded $0.4 million, net of taxes of $0.2 million, of derivative gains 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 ineffectiveness reported in "Price-risk management and other, net" for the first quarters of 2006 and 2005 were 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, 2006, we had in place price floors in effect for April 2006 through the June 2006 contract month for natural gas that cover a portion of our domestic natural gas production for April 2006 to June 2006. The natural gas price floors cover notional volumes of 1,275,000 MMBtu, with a weighted average floor price of $8.00 per MMBtu. Our natural gas price floors in place at March 31, 2006 are expected to cover approximately 35% to 45% of our estimated domestic natural gas production from April 2006 to June 2006.

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, 2006, was $1.1 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 $2.0 million in the first quarter of 2006 and $1.7 million in the first quarter of 2005.

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 well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the 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. 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:

		2006
Asset Retirement Obligation recorded as of January 1	$	19,356,367
Accretion expense for the three months ended March 31		291,515
Liabilities incurred for new wells and facilities construction		174,139
Reductions due to sold, or plugged and abandoned wells		---
Decrease due to currency exchange rate fluctuations		(60,697)
Asset Retirement Obligation as of March 31	$	19,761,324

At both March 31, 2006 and December 31, 2005, approximately $0.3 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

EITF 04-05 addresses when a limited partnership should be consolidated by its general partner. EITF 04-05 presumes that a sole general partner in a limited partnership controls the limited partnership, and therefore should consolidate the limited partnership. The presumption of control can be overcome if the limited partners have (a) the substantive ability to remove the sole general partner or otherwise dissolve the limited partnership or (b) substantive participating rights. The EITF reached a tentative conclusion on the circumstances in which either kick-out rights or participating rights would be considered substantive and preclude consolidation by the general partner. The FASB ratified the EITF consensus at the June 2005 EITF meeting. This EITF was adopted January 1, 2006 and did not have a material impact on our consolidated financial statements because we believe our limited partners have substantive kick-out rights under paragraph B20 of FIN 46R.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections: a replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires voluntary changes in accounting principles to be applied retrospectively, unless it is impracticable. SFAS No. 154's retrospective application requirement replaces APB 20's requirement to recognize most voluntary changes in accounting principle by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. If retrospective application for all prior periods is impracticable, the method used to report the change and the reason the retrospective application is impracticable are to be disclosed.

Under SFAS No. 154, retrospective application will be the transition method in the unusual instance that a newly issued accounting pronouncement does not provide specific transition guidance. It is expected that many pronouncements will specify transition methods other than retrospective. SFAS No. 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005, and the adoption of this statement had no impact on our financial position or results of operations.

In July 2005, the FASB issued an exposure draft "Accounting for Uncertain Tax Positions, a proposed interpretation of FASB Statement No. 109." The proposed interpretation would apply to all open tax positions under FASB No. 109. The conclusions in this interpretation include: initial recognition of tax benefits, recognition and de-recognition of tax positions, measurement of tax benefits and classifications of tax liabilities. The comment period on this exposure draft ended in September 2005, and we are currently assessing the impact, if any, that this interpretation would have on our financial position and results of operations. The FASB has not issued an effective date for this interpretation, and a final standard will likely be issued in 2006.

(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, 2005, 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 the three months ended March 31, 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.

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the three months ended March 31, 2006, were $1.1 million, $0.7 million, $0.02, and $0.02 lower, respectively, than if we had continued to account for share-based compensation under APB Opinion No. 25 for our stock option grants. 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 totaled $0.6 million for the three months ended March 31, 2006.

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

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 statement of income, and was $1.7 million and $0.1 million for the three months ended March 31, 2006 and 2005, 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.

The following table illustrates the effect on March 31, 2005 operating results and per share information had the Company accounted for share-based compensation in accordance with SFAS No. 123R. Our net income and earnings per share would have been adjusted to the following pro forma amounts:

	Three Months Ended March 31, 2005

Net Income:	As Reported	$25,689,152
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(859,151)
	Pro Forma	$24,830,001
Basic EPS:	As Reported	$.91
	Pro Forma	$.88
Diluted EPS:	As Reported	$.89
	Pro Forma	$.86

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, 2006	2005
Dividend yield	0%	0%
Expected volatility	40%	40%
Risk-free interest rate	4.8%	3.5%
Expected life of options (in years)	6.3	3.2
Weighted-average grant-date fair value	$ 21.02	$ 8.40

The expected term has been calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulleting No. 107. We have analyzed historical volatility and based on an analysis of all relevent factors use a three-year period to estimate expected volatility of our stock option grants.

14

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

At March 31, 2006, there was $5.9 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, 2006:

	March 31, 2006	
	Wtd. Avg. Exer.	Wtd. Avg. Contract

	Shares	Price	Life
Options outstanding, beginning of period	2,118,179	$ 21.28	
Options granted	139,339	$ 44.14	
Options canceled	(24,440)	$ 19.02	
Options exercised	(71,785)	$ 17.59	
Options outstanding, end of period	2,161,293	$ 22.87	5.8 Yrs
Options exercisable, end of period	1,140,761	$ 21.52	4.6 Yrs

The aggregate intrinsic value of options outstanding at March 31, 2006 was $33.2 million, and the aggregate intrinsic value of options exercisable was $18.2 million. Total intrinsic value of options exercised was $1.9 million for the three months ended March 31, 2006.

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, 2005, 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 18 months 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 numbers of shares that were anticipated to fully vest. As of March 31, 2006, we have unrecognized compensation expense of $10.0 million associated with these awards which are expected to be recognized over a weighted-average period of 2.5 years.

The following table represents restricted stock activity for the three months ended March 31, 2006:

	March 31, 2006	
	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	236,950	$ 34.79
Restricted shares granted	114,980	$ 43.68
Restricted shares canceled	(10,230)	$ 39.51
Restricted shares vested	(14,180)	$ 25.18
Restricted shares outstanding, end of period	327,520	$ 41.56

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(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 antidilutive for periods ended March 31, 2006 and 2005, 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, 2006 and 2005:

	Three Months Ended March 31,			
	2006			2
	Net Income	Shares	Per Share Amount	Net Income
Basic EPS:				
Net Income and Share Amounts......	$ 37,314,506	29,071,764	$ 1.28	$ 25,689,152
Dilutive Securities:				
Restricted Stock	---	78,501		---
Stock Options	---	845,633		---
Diluted EPS:				
Net Income and Assumed Share Conversions	$ 37,314,506	29,995,898	$ 1.24	$ 25,689,152

Options to purchase approximately 2.2 million shares at an average exercise price of $22.87 were outstanding at March 31, 2006, while options to purchase 2.9 million shares at an average exercise price of $18.97 were outstanding at March 31, 2005. Approximately 1.6 million and 0.7 million stock options and non-vested shares of restricted stock were not included in the computation of Diluted EPS for the periods ended March 31, 2006, and 2005, respectively, because these options were antidilutive in that the option price was greater than the average closing market price for the common shares during those periods. Restricted stock grants to consultants of 1,200 shares, were not included in the computation of Diluted EPS for the period ended March 31, 2006, as performance conditions surrounding the vesting of these shares had not occurred.

(5) Long-Term Debt

Our long-term debt, including the current portion, as of March 31, 2006 and December 31, 2005, was as follows (in thousands):

	March 31,	December 31,

	2006	2005
Bank Borrowings	$ ---	$
7-5/8% senior notes due 2011	150,000	150,
9-3/8% senior subordinated notes due 2012 ...	200,000	200,
Long-Term Debt	$ 350,000	$ 350,

Bank Borrowings

At March 31, 2006, we had no outstanding borrowings under our $400.0 million credit facility with a syndicate of ten banks that has a borrowing base of $250.0 million and expires in October 2008. The interest rate is either (a) the lead bank's prime rate (7.75% at March 31, 2006) 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 June 2004, we renewed this credit facility, increasing the facility to $400 million from $300 million and extending its expiration to October 1, 2008 from October 1, 2005. The other terms of the credit facility, such as the borrowing base amount and commitment amount, stayed largely the same. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred $0.4 million of debt issuance costs related to the renewal of this facility in 2004, which is included in "Debt issuance costs" on the accompanying balance sheets and will be amortized to interest expense over the life of the facility.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $5.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $15.0 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 or 9-3/8% senior subordinated notes due 2012. 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. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group at $250.0 million effective May 1, 2006. We requested that the commitment amount with our bank group be reduced to $150.0 million effective May 9, 2003. Under the terms of the credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The next scheduled borrowing base review is in November

2006.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.2 million and $0.3 million for the first quarters of 2006 and 2005, respectively. The amount of commitment fees included in interest expense, net was $0.1 million for both the first quarters of 2006 and 2005.

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 in both the first quarter of 2006 and 2005.

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. In addition, prior to May 1, 2005, we could have redeemed up to 33.33% of these notes with the net proceeds of qualified offerings of our equity at 109.375% of the principal amount of these notes, plus accrued and unpaid interest. 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 in both the first quarters of 2006 and 2005.

The aggregate maturities on our long-term debt are $150 million for 2011 and $200 million for 2012.

We have capitalized interest on our unproved properties in the amount of $2.1 million and $1.8 million, for the first quarters of 2006 and 2005, respectively.

(6) Foreign Activities

As of March 31, 2006, our gross capitalized oil and gas property costs in New Zealand totaled approximately $305.6 million. Approximately $273.5 million has been included in the "Proved properties" portion of our oil and gas properties, while $32.1 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 $252.1 million at March 31, 2006.

(7) Acquisitions and Dispositions

In November 2005, we acquired interests in the South Bearhead Creek field in Central Louisiana. This field is approximately 50 miles south of our Masters Creek field. We paid approximately $24.3 million in cash for these interests. After taking into account internal acquisition costs of $2.6 million, and assumed liabilities of $1.4 million, our total cost was $28.3 million. We allocated $26.2 million of the acquisition price to "Proved properties," $2.5 million to "Unproved properties," and recorded a liability for $0.4 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. In December 2005 we acquired additional interests in this field. We paid approximately $4.6 million in cash for these additional interests. After taking into account internal acquisition costs of $0.6 million, our total cost was $5.2 million. We allocated $4.9 million of the acquisition price to "Proved properties," $0.4 million to "Unproved properties," and recorded a liability for $0.1 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 this area. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward, however, given the acquisitions were in November and December 2005, these amounts were immaterial for 2005.

(8) Subsequent Events

In April 2006, we sold our minority interests in the Brookeland and

Masters Creek natural gas processing plants for approximately $20.3 million in cash. Under the "full-cost" method of accounting for oil and gas property and equipment costs, the proceeds of this sale will be applied against our oil and gas properties and equipment balance, and no gain or loss will be recognized on this transaction.

18

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(9) 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 1). As part of this restructuring our indentures were amended so that 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 this restructure, 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 000's)	March 31, 2006		
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries
ASSETS			
Current assets	$ ---	$ 135,829	$ 26,357
Property and equipment	---	910,152	222,615
Investment in subsidiaries (equity method)	650,162	---	449,968
Other assets	---	33,813	609
Total assets	$ 650,162	$ 1,079,794	$ 699,549
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities	$ ---	$ 96,262	$ 16,834
Long-term liabilities	---	533,564	32,553
Stockholders' equity	650,162	449,968	650,162
Total liabilities and stockholders' equity	$ 650,162	$ 1,079,794	$ 699,549

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(in 000's)	December 31, 2005		
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries
ASSETS			
Current assets	$ ---	$ 92,788	$ 22,267
Property and equipment	---	862,717	216,316
Investment in subsidiaries (equity method)	607,318	---	410,612
Other assets	---	31,955	682
Total assets	$ 607,318	$ 987,460	$ 649,877
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities	$ ---	$ 85,472	$ 12,949
Long-term liabilities	---	491,376	29,610
Stockholders' equity	607,318	410,612	607,318
Total liabilities and stockholders' equity	$ 607,318	$ 987,460	$ 649,877

Condensed Consolidating Statements of Income

(in 000's)	Three Months Ended March 31,		
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries
Revenues	$ ---	$ 119,438	$ 16,731
Expenses	---	65,798	12,596
Income (loss) before the following:	---	53,640	4,135
Equity in net earnings of subsidiaries	37,315	---	33,828

Income before income taxes	37,315	53,640	37,963
Income tax provision (benefit)	---	19,812	648
Net income	$ 37,315	$ 33,828	$ 37,315

20

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(in 000's)	Three Months Ended March 31, 200		
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations
Revenues	$ 76,768	$ 18,855	$ (2
Expenses	44,437	11,427	(2
Income (loss) before the following:	32,331	7,428	---
Equity in net earnings of subsidiaries	5,379	---	(5,379
Income before income taxes	37,710	7,428	(5,379
Income tax provision (benefit)	12,020	2,049	---
Net income	$ 25,690	$ 5,379	$ (5,379

Condensed Consolidating Statements of Cash Flows

(in 000's)	Three Months Ended March 31, 20			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Elim
Cash flow from operations	$ ---	$ 76,061	$ 7,839	$
Cash flow from investing activities	---	(71,734)	(13,637)	

Cash flow from financing activities	---	1,535	2,157	
Net increase in cash	$ ---	$ 5,862	$ (3,640)	$
Cash, beginning of period	---	44,911	8,094	
Cash, end of period	$ ---	$ 50,773	$ 4,454	$

21

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS-Continued
SWIFT ENERGY COMPANY AND SUBSIDIARIES

(in 000's)	Three Months Ended March 31, 200		
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations
Cash flow from operations	$ 50,871	$ 13,781	$
Cash flow from investing activities	(39,834)	(15,147)	1,
Cash flow from financing activities	(6,659)	1,783	(1,
Net increase (decrease) in cash	4,378	417	
Cash, beginning of period	205	4,715	
Cash, end of period	$ 4,583	$ 5,132	$

(10) Segment Information

The Company has two reportable segments, one domestic and one foreign, which are in the business of crude 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

	2006			
	Domestic	New Zealand	Total	Domestic
Oil and gas sales	$ 118,084,694	$ 16,868,299	$ 134,952,993	$ 76,775,76
Costs and Expenses:				
Depreciation, depletion and amortization	28,021,752	7,384,745	35,406,497	17,673,69
Accretion of asset retirement obligation	255,672	35,843	291,515	153,85
Lease operating costs	11,307,560	3,086,929	14,394,489	8,244,21
Severance and other taxes	13,607,937	1,145,669	14,753,606	8,030,68
Income from oil and gas operations	$ 64,891,773	$ 5,215,113	$ 70,106,886	$ 42,673,31
Price-risk management and other, net			1,215,938	
General and administrative, net			7,686,909	
Interest expense, net			5,860,919	
Income Before Income Taxes			$ 57,774,996	
Total Assets	$ 1,052,793,307	$ 252,111,859	$ 1,304,905,166	$ 800,313,77

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 Form 10-K for the year ended December 31, 2005. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Statements" on page 32 of this report.

Overview

Swift Energy had record net income and production for the first quarter of 2006. Net income increased 45% to $37.3 million and production increased 7% to 16.6 Bcfe over first quarter 2005 levels. Cash flow from operating activities increased 30% to $83.9 million over first quarter 2005 levels. We also had record revenues of $136.2 million for the first quarter of 2006, an increase of 42% over 2005 first quarter levels. The strong commodity prices during the first quarter of 2006 and increases in production supported the increase in our revenues as compared to the same period in 2005.

Our efforts and capital throughout the first quarter of 2006 remained primarily focused on infrastructure improvements, increased production, and the development of long-lived reserves through exploration and exploitation activities primarily in four of our regions: South Louisiana, South Texas, Toledo Bend, and New Zealand. We expect to continue this focus throughout 2006. We are reviewing further potential capacity increases of our facilities in Lake Washington, and expect the new 3-D seismic survey over the Cote Blanche Island area to be completed in the third quarter of 2006, and have recently acquired seismic on our offshore Kaheru exploration permit in New Zealand. In March 2006, we signed a participation agreement to explore several sites in onshore Alaska's Cook Inlet Basin. Under the joint venture we will have a 37.5% working interest in about 54,500 acres. We started drilling an exploratory well, in which we own a 50% working interest, on this acreage in April 2006.

Our overall costs and expenses increased in the first quarter of 2006. Although costs for equipment and services are continuing to rise in the industry at this time, we are working to manage our costs and expenses to remain at this same general level for the remainder of 2006. The largest increase in these costs and expenses is due to increased depreciation, depletion and amortization expense as a result of increased estimates for future development costs and additional capital expenditures over prior year levels. We experienced higher costs due to increased oil production in Lake Washington, along with higher severance taxes due to increased revenues. We also saw an increase in our general and administrative expenses due to an increased workforce and stock compensation expense associated with the adoption of FAS No. 123(R). We expect cost pressures to continue to affect the industry throughout 2006, especially along the Gulf Coast following the two 2005 hurricanes, with tightening availability of crews as well as increasing costs of services and basic equipment.

Our financial position remains strong and flexible, allowing us to take advantage of future opportunities for organic growth through drilling and strategic growth through acquisitions. Our financial ratios have also continued to improve. Our debt to capitalization ratio was 35% at March 31, 2006 compared to 37% at year-end 2005, as debt levels remained at the same level as year-end 2005 and retained earnings increased as a result of the current period profit. Including our cash on hand at the end of the quarter, our net debt to capital ratio would have been 29%.

There are a number of factors that support our belief that Swift Energy's performance for 2006 will be strong. We think that strong commodity prices will continue over the foreseeable future, based in part on forward-strip pricing. Although production was impacted by the hurricane activity in the second half of 2005, all of Swift Energy's operations in the South Louisiana region are back on production at or above pre-Katrina production levels, except for the Cote Blanche Island field. Cote Blanche Island is expected to be back online during the second quarter of 2006. Our merged 3-D seismic data offsets around our fields in southern Louisiana have yielded success in our exploration and development activities, as demonstrated by our year-end drilling successes at our Newport and Bondi prospects in the Lake Washington area. Continued work-over and recompletion activity is expected to take place in 2006, particularly in the Bay de Chene and Cote Blanche Island fields in southern Louisiana; however, this work has been delayed somewhat due to our recovery efforts from Hurricanes Katrina and Rita. We also acquired additional property in our Toledo Bend region during the fourth quarter of 2005, the South Bearhead Creek property. Our diversified drilling portfolio positions us for higher impact exploration drilling as well as expanded exploitation efforts in 2006.

Results of Operations - Three Months Ended March 31, 2006 and 2005

Revenues. Our revenues in the first quarter of 2006 increased by 42% compared to revenues in the same period in 2005, due primarily to an increase in commodity prices and the production increase principally from our Lake Washington field. Revenues from our oil and gas sales comprised substantially all of net revenues for the first quarter of 2006 and 2005. In the first quarter of 2006, oil production made up 58% of total production, natural gas made up 36%, and NGL represented 6%. In the first quarter of 2005, oil production made up 51% of total production, natural gas made up 40%, and NGL represented 9%. The percentage of our total production from oil increased as Lake Washington production, which is almost entirely oil, increased over first quarter of 2005 levels.

Our first quarter 2006 weighted average prices increased 32% to $8.14 per Mcfe from $6.16 in the first quarter of 2005, with oil prices appreciating 28% to $60.83 from $47.66 during the first quarter of 2005, natural gas prices increasing 27% to $5.38 from $4.25, and NGL prices rose 13% to $30.34 from $26.79.

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, 2006 and 2005.

	Three Months Ended March 31,		
Area	Oil and Gas Sales (In Millions)		Net Oil and Gas Sales
	2006	2005	2006
AWP Olmos	$ 15.3	$ 11.3	1.9
Brookeland	4.3	4.0	0.5
Lake Washington	85.3	51.4	8.7
Masters Creek	3.9	4.7	0.5
Other	9.3	5.4	1.2
Total Domestic	$ 118.1	$ 76.8	12.8
Rimu/Kauri	8.7	12.5	1.6
TAWN	8.2	6.2	2.2
Total New Zealand ...	$ 16.9	$ 18.7	3.8

Total	$ 135.0	$ 95.5	16.6	

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

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

	Sales Volume				Average
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)
2006					
Three Months Ended March 31:					
Domestic	1,487	90	3.3	12.8	$60.56
New Zealand	124	62	2.7	3.8	$64.13
Total	1,611	152	6.0	16.6	$60.83
2005					
Three Months Ended March 31:					
Domestic	1,184	143	3.0	11.0	$47.20
New Zealand	137	80	3.3	4.5	$51.68
Total	1,321	223	6.3	15.5	$47.66

In the first quarter of 2006, our $39.4 million increase in oil, NGL, and natural gas sales resulted from:

- oPrice variances that had a $28.5 million favorable impact on sales, of which $21.2 million was attributable to the 28% increase in average oil prices received, $6.8 million was attributable to the 27% increase in average gas prices received, and $0.5 million was attributable to the 13% increase in average NGL prices received; and

- oVolume variances that had a $10.9 million favorable impact on sales, with $13.9 million of increases coming from the 290,000 Bbl increase in oil sales volumes, offset by $1.1 million of decreases due to the 0.3 Bcf decrease in gas sales volumes, and $1.9 million of decreases attributable to the 71,000 Bbl decrease in NGL sales volumes.

Costs and Expenses. Our expenses in the first quarter of 2006 increased $22.5 million, or 40%, compared to expenses in the same period of 2005. The increase was due to an $11.2 million increase in DD&A, a $5.6 million increase in severance and other taxes, and a $3.3 million increase in lease operating costs, all of which are primarily due to increased production volumes and higher oil and gas prices in the first quarter of 2006.

Our first quarter 2006 general and administrative expenses, net, increased $2.8 million, or 58%, from the level of such expenses in the same 2005 period. This increase was primarily due an increase in stock compensation expense resulting from the adoption of SFAS No. 123R. Our stock compensation expense recorded in general and administrative, net increased by $1.6 million, net of capitalized amounts, over first quarter of 2005 levels. For the first quarters of 2006 and 2005, our capitalized general and administrative costs, excluding stock compensation, totaled $6.0 million and $4.1 million, respectively. Our capitalized general and administrative expenses increased due to the expansion of our workforce and the capitalization of stock compensation related to geological and geophysical workforce. Our net general and administrative expenses per Mcfe produced increased to $0.46 per Mcfe in the first quarter of 2006 from $0.31 per Mcfe in the same 2005 period. The portion of supervision fees recorded as a reduction to general and administrative expenses was $2.0 million for the first quarter of 2006 and $1.7 million for the 2005 period.

DD&A increased $11.2 million, or 46%, in the first quarter of 2006 from the level of those expenses in the same period of 2005. Domestically, DD&A increased $10.3 million in the first quarter of 2006 due to increases in the depletable oil and gas property base, including future development costs and higher production in the 2006 period. In New

Zealand, DD&A increased by $0.9 million in the first quarter of 2006 due to increases in the depletable oil and gas property base and lower reserves volumes, partially offset by lower production in the 2006 period. Our DD&A rate per Mcfe of production was $2.13 and $1.56 in the first quarters of 2006 and 2005, respectively.

We recorded $0.3 million and $0.2 million of accretions to our asset retirement obligation in the first quarters of 2006 and 2005, respectively.

Our lease operating costs per Mcfe produced were $0.87 in the first quarter of 2006 and $0.71 in the first quarter of 2005. Our lease operating costs in the first quarter of 2006 increased $3.3 million, or 30%, over the level of such expenses in the same 2005 period. Almost all of the increase was related to our domestic operations, which increased primarily due to higher production from our Lake Washington area and higher insurance costs. Our lease operating costs in New Zealand increased in the first quarter of 2006 by $0.3 million due to higher well operating costs.

In the first quarter of 2006, severance and other taxes increased $5.6 million, or 60%, over levels in the first quarter of 2005. The increase was due primarily to higher commodity prices and increased Lake Washington production. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than 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 10.9% and 9.6% in the first quarters of 2006 and 2005, respectively.

Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $3.0 million in the first quarter of 2006. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002, including amortization of debt issuance costs, totaled $4.8 million in both the first quarter of 2006 and 2005. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.2 million in the first quarter of 2006 and $0.3 million in the same period in 2005. Our total interest cost in the first quarter of 2006 was $8.0 million, of which $2.1 million was capitalized. Our total interest cost in the first quarter of 2005 was $8.1 million, of which $1.8 million was capitalized. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in the first quarter of 2006 was primarily attributable to higher capitalized costs along with lower credit facility costs resulting from a decrease in borrowings against the credit facility.

Our overall effective tax rate was 35.4% in both the first quarter of 2006 and 2005. The effective income tax rate for both the first quarter of 2006 and 2005 was lower than the statutory tax rates primarily due to reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation.

Net Income. For the first quarter of 2006, our net income of $37.3 million was 45% higher, and Basic EPS of $1.28 was 41% higher, than our first quarter of 2005 net income of $25.7 million and Basic EPS of $0.91. Our Diluted EPS in the first quarter of 2006 of $1.24 was 40% higher than our first quarter 2005 Diluted EPS of $0.89. These higher amounts are due to our increased oil and gas revenues, which in turn were higher due to continued strong commodity prices and increased production during the first quarter of 2006.

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 prior period levels.

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

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 the three months ended March 31, 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.

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the three months ended March 31, 2006, were $1.1 million, $0.7 million, $0.02, and $0.02 lower, respectively, than if we had continued to account for share-based compensation under APB Opinion No. 25 for our stock option grants. 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, 2006	Three Months Ended March 31, 2005
Dividend yield	0%	0%
Expected volatility	40%	40%
Risk-free interest rate	4.8%	3.5%
Expected life of options (in years)	6.3	3.2
Weighted-average grant-date fair value	$ 21.02	$ 8.40

The expected term has been calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulleting No. 107. We have analyzed historical volatility and based on analysis of all relevant factors use a three-year perior 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.

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. At March 31, 2006, there was $5.9 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 $10.0 million related to restricted stock awards which are expected to be recognized over a weighted-average period of 2.5 years.

Contractual Commitments and Obligations

We had no material changes in our contractual commitments and obligations from December 31, 2005 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, 2005.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last two years and is currently significantly higher when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, weather conditions, actions taken by OPEC, and fluctuating currency exchange rates 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